Aalto-yliopisto
Insinööritieteiden
korkeakoulu

Oliver Joukama

Smart electricity grid in Finland – Feeder automation

Thesis submitted in partial fulfillment of the requirements
for the degree of Master of Science in Technology

Espoo 20.03.2017
Supervisor: Professor Sanna Syri
Advisor: German Orjuela, M.Sc (Tech.)

Aalto University
School of Engineering

Aalto University, P.O. BOX 11000, 00076 AALTO
www.aalto.fi

Abstract of master's thesis

Author Oliver Joukama

Title of the thesis Smart electricity grid in Finland – Feeder automation

Degree programme Energy and HVAC-Technology

Major Energy Technology: Energy Technology for Communities and Energy Economics **Code** K328-3

Thesis supervisor Sanna Syri, Professor

Thesis advisor German Orjuela, M.Sc (Tech.)

Date 20.03.2017 **Number of pages** 80 **Language** English

Abstract

Smart grid is an umbrella term, which describes an electricity grid, where next generation technologies connect all stakeholders with each other, in order to operate the system as efficiently and reliably as possible. For medium voltage network, smart grid means more distribution automation. Feeder automation, which is a part of distribution automation, refers to the control and monitoring of secondary substations and disconnector stations. Biggest benefit of feeder automation is related to fault management. The Electricity Market Act (2013) and the new regulation model (2016 – 2023) are both driving forward the feasibility of feeder automation.

This thesis studied the current state of the Finnish smart medium voltage network by interviewing six large distribution companies. The interviews also investigated the companies' opinions regarding the future of smart gird technologies, and opinions towards regulations driving smart grid technologies. The biggest, but still relatively minor, concern the Finnish distribution companies had with the current regulation and legislation, was the lack of flexibility in the 'component value list' in the regulation model. This lack of flexibility does not encourage large-scale investments towards new technologies, if the particular component is not on the 'list'. The most common expectations of future smart grid technologies were related to better fault detection. The increase of PV production was not seen as a major issue in the coming years.

This thesis also studied the feasibility of feeder automation. The feasibility study was conducted by a case study related to the optimum automation level for a predetermined network topology. All the parameters for this case study, such as length of the feeders, power demand and outage restoration time, are based on technical figures published by the Energy Authority. The price of the technology is based on the new regulation model's 'component value list', published by the Energy Authority. The results were calculated for different fault frequency values. The optimum automation level for 1 fault/year was 22 %.

Keywords smart grid and feeder automation

Aalto-yliopisto
Insinööritieteiden
korkeakoulu

Aalto-Yliopisto, PL 11000, 00076 AALTO
www.aalto.fi

Diplomityön tiivistelmä

Tekijä Oliver Joukama	
Työn nimi Älykäs sähköverkko Suomessa - Muuntamoautomaatio	
Koulutusohjelma Oliver Joukama	
Pääaine Energiatekniikka: Yhdyskuntien energiatekniikka ja energiatalous	**Koodi** K328-3
Työn valvoja Professori Sanna Syri	
Työn ohjaaja DI German Orjuela	
Päivämäärä 20.3.2017 **Sivumäärä** 80	**Kieli** Englanti

Tiivistelmä

Älykäs sähköverkko on sateenvarjotermi, joka kuvaa sähköverkkoa, jossa uuden sukupolven teknologiat yhdistävät sähkömarkkinoiden kaikki sidosryhmät keskenään, mahdollistaen tehokkaamman ja luotettavamman sähköjärjestelmän. Keskijännitejakeluverkolle älykkyys tarkoittaa automaatiota. Muuntamoautomaatio, joka on osa jakeluverkon automaatiota, viittaa muuntamoiden ja erotinasemien hallintaan ja monitorointiin. Suurin hyöty muuntamoautomaatiossa syntyy vian hallinnan kautta. Sähkömarkkinalaki (2013) ja uusi Valvontamenetelmä (2016 – 2023) molemmat ajavat eteenpäin muuntamoautomaation kannattavuutta.

Tämä tutkielma tutki Suomen nykyistä älykästä keskijänniteverkkoa haastattelemalla kuutta suurta jakeluverkkoyhtiötä. Haastatteluilla tutkittiin myös jakeluverkkoyhtiöiden näkemyksiä ja mielipiteitä tulevaisuuden teknologioita ja nykyistä regulaatiota kohtaan. Yleisin, vaikkakin vähäinen, verkkoyhtiöiden kehitysehdotus liittyi valvontamenetelmän verkkokomponenttilistan jäykkyyteen. Jos uutta teknologiaa ei löydy kyseiseltä listalta, ei se kannusta kyseisen teknologian massa-asennukseen. Suurimmat odotukset uusiin älykkäisiin teknologioihin liittyi vian havaitsemiseen. Paikallisen aurinkosähkön tuotannon ei nähty aiheuttavan merkittäviä haasteita jakeluverkolle lähitulevaisuudessa.

Tämä tutkielman tutki myös muuntamoautomaation kannattavuutta. Kannattavuusanalyysi tehtiin tapaustutkimuksen avulla, laskemalla optimaalisen automaatiotason eri vikatiheysarvoille. Tapaustutkimuksena käytettiin ennalta määrättyä verkkotopologiaa. Kaikki jakeluverkkoon liittyvät parametrit, kuten johtolähtöjen tehot, pituudet ja vian korjausaika, ovat laskennallisia keskiarvolukuja Energiaviraston julkaisemista teknillisistä tunnusluvuista. Muuntamoautomaation hintana on käytetty Valvontamenetelmän (2016 – 2023) verkkokomponenttilistan määrittämiä hintoja. Tapaustutkimuksessa vikatiheydelle 1 vika/vuosi laskettiin optimaaliseksi automaatiotasoksi 22 %.

Avainsanat älykäs sähköverkko ja muuntamoautomaatio

Acknowledgements

This thesis was conducted to Schneider Electric Finland Oy's Energy team. I want to express my deepest gratitude towards the whole Schneider Electric Oy Energy team for supporting me with this thesis, especially M.Sc. German Orjuela, who taught me so much about the subject. Mr. Orjuela was the primary advisor of this thesis. I also want to thank my supervisor at Schneider Electric, Mikko Keto, for fully supporting me during this whole process.

I also want to express my deepest gratitude the whole Schneider Electric Finland Oy for giving me this opportunity to conduct a thesis about an interesting topic. Schneider Electric Finland Oy, as a company, has been 100 % supportive regarding the completion of this thesis.

I also want to express my deepest gratitude to all my interviewees, who gave their time to participate in this thesis. Everyone that was interviewed, helped me tremendously, and not just by answering the required questions, but also by giving useful tips and knowledge about the subject.

Espoo 20.3.2017

Oliver Joukama

Table of Contents

Abstract
Acknowledgements
Table of Contents 5
List of Abbreviations 7
1 Introduction 9
1.1 Research questions 9
2 Defining the Smart grid concept 10
2.1 Official definitions 10
2.2 Motive for smart grids 11
2.3 Difference between a smart grid and a conventional grid 12
3 Smart Grid trends 16
3.1 Demand response 16
3.1.1 Different demand response programs 16
3.1.2 The benefits of demand response 18
3.1.3 Demand response in Finland 19
3.1.4 Demand Bidding Program example in New York City 20
3.1.5 DR challenges 21
3.2 Distributed generation 21
3.2.1 DG and the distribution network 22
3.2.2 DG market situation and trends in Finland 23
3.3 Challenges for smart grid development 24
3.3.1 Regulatory challenges 24
3.3.2 Cyber security and privacy 25
4 Overview of the technologies used to operate the Finnish distribution network 26
4.1 Background 26
4.2 Description of the Finnish distribution network 27
4.3 Distribution network management at company level 28
4.3.1 Geographical Information System 28
4.3.2 Customer Information System 29
4.3.3 Automatic Meter Management 29
4.4 Distribution network management at control center level 29
4.4.1 SCADA 30
4.4.2 Distribution Management System 30
4.4.3 Outage Management System 31
4.5 Substation and feeder automation 31
4.6 Advanced Metering Infrastructure 32
5 Government and the EU driving the smart grid development 34
5.1 Operational environment in Finland 34
5.2 Electricity market act (2013) 34
5.2.1 Maximum outage duration requirement 35
5.3 Relevant changes to the regulation model 37
5.4 European Union’s effect on Finland’s smart grid development 39
5.4.1 Smart grid mandate 39
5.4.2 Smart meter mandate 39
5.4.3 European Electricity Grid Initiative (EEGI) 40
6 Improving system reliability with feeder automation RTUs 41

6.1 Background 41
6.1.1 Underground network and system reliability 41
6.2 How to quantify system reliability? 43
6.3 The cost of an outage 44
6.4 Benefits of feeder automation 45
6.4.1 Benefits of better fault management with feeder automation 45
6.4.2 Estimating SAIDI reduction potentials for different feeder automation technologies 47
6.4.3 Benefits of Volt/Var optimization and power quality monitoring 48
6.4.4 Benefits through better asset management 49
6.4.5 Added network value from feeder automation RTUs 49
6.5 Potential savings through CAIDI reduction on a specific MV feeder 49
6.6 Optimizing feeder automation in MV networks 51
6.7 Example of a feeder automation RTU 52
7 Interviews: DSO’s current feeder automation level and view of the smart grid 54
7.1 Background 54
7.2 Answers and discussion 55
8 Case: Optimizing the number of feeder automation RTUs in an underground ring network 59
8.1 Description the optimization problem 59
8.2 Objective function, decision variables and parameters 60
8.3 Results 64
8.4 Discussion about the results 65
9 Conclusion 68
References 70
Appendix: Interviews 76

List of Abbreviations

AMI	Advanced Metering Infrastructure
AMI-SEC Task Force	Advanced Metering Infrastructure Security Task Force
AMM	Advanced Meter Management
CEN	European Committee for Standardization
CENELEC	European Committee for Electrotechnical Standardization
CIS	Customer Information System
DG	Distributed Generation
DMS	Distribution Management System
DR	Demand Response
DSO	Distribution System Operator
EDSO	European Distribution System Operators
EEGI	European Electricity Grid Initiative
EFTA	European Free Trade Association
ENTSO-E	European Network of Transmission System Operators
ESMIG	European Smart Meters Industry Group
ESO	European Standards Organization
ETSI	European Telecommunications Standards Institute
EURELECTRIC	Union of the Electricity Industry
FPI	Fault Passage Indicator
GIS	Geographical Information System
IBP	Incentive Based Programs
IEA	International Energy Agency
IED	Intelligent Electronic Device
IEEE	The Institute of Electrical and Electronics Engineers
LV	Low Voltage
MDM	Meter Data Management
MED	Major Event Day
MV	Medium Voltage
NIS	Network Information System
NIST	National Institute of Standards and Technology
OMS	Outage Management System
PBP	Price Based Programs
RD&D	Research, Development and Demonstration
RTP	Real Time Pricing
RTU	Remote Thermal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control And Data Acquisition
SET-PLAN	Strategic Energy Technologies Plan
SG-CG	Smart Grid Coordination Group

SM-CG	Smart Meters Coordination Group
TOU	Time of Use

1 Introduction

The Finnish distribution companies are facing a change. The future electricity grid has to address challenges related to intermittent renewable electricity generation and power continuity. Smart grid technologies play a key role in addressing these challenges. This thesis is going to discuss, how smart grid technologies are changing the current power system in Finland, and what trends are currently forming the current power system. Some smart grid trend examples are brought up from outside of Finland. The focus point of this thesis will start from the overall concept of smart grid. After this, the focus will narrow down to the distribution network level, keeping the distribution companies' interests in the center of attention. The technologies used by Finnish Distribution System Operators (DSO) are described, without going into technical details. In addition, the relevant legislations and regulations affecting the distribution companies' implementation of new smart grid technologies are discussed. Via interviews, the thesis is going to dive deeper into Finnish DSOs' views on future smart grid trends, and their views on the current regulations and legislations affecting the implementation smart grid technologies. The interview also investigates the distribution companies' current automation level at medium voltage (MV) level. These views and the information about the current status of the grid, have been collected through face-to-face interviews with major Finnish distribution companies.

The second part of this thesis will focus on feeder automation and its benefits for the DSOs. Feeder automation describes the smart grid technologies used at the MV network level. In short, feeder automation includes all the technologies, which are increasing the monitoring and controllability of feeders beyond primary substations, excluding everything that happens on the low voltage circuits (e.g. smart meters). The focus point will stay on the benefits DSOs get from feeder automation technologies, emphasizing the monetary benefits. Because benefits of feeder automation rotate heavily on reducing outage times, the cost of outages and the ways feeder automation can reduce outages are discussed as well. The feasibility of reducing outages with feeder automation is studied through a case study, where the optimum feeder automation level is determined for an average Finnish underground ring network topology, using Energy Authority's new cost estimations for the instalment of feeder automation technologies.

1.1 Research questions

This thesis investigates two research questions related to smart grid technologies and feasibility of feeder automation:

1. How do the Finnish distribution companies see the future of smart grid technologies in their distribution network?
2. How are Energy Authority's new cost estimations on feeder automation technologies affecting the investment feasibility of the technology?

2 Defining the Smart grid concept

2.1 Official definitions

Smart grid does not have a universal definition, but the term is typically used to describe an electricity grid, which includes next generation technologies, such as wireless communication and remote control. When talking about smart grids, one can refer to any part of the power system from producer to the end-user. This thesis is focusing on the distribution network.

The term 'smart grid' is relatively new, but first 'smart' applications for the distribution network were developed in the 1970's, when the first remote operating and monitoring systems were introduced. After this, the evolution of a smarter electricity distribution network has been a continuous process. (Staszesky et al. 2005)

Smart grid is broad term, which consists of almost all innovations related to the entire power system. Three different official definitions by different prominent stakeholders are listed below.

In EU, the official definition of a smart grid is represented in '*Mandate M/490 for smart grids'* published by EURELECTRIC (Union of the Electricity Industry) in 2011:

"A Smart Grid is an electricity network that can cost efficiently integrate the behavior and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety." (EURELECTRIC 2011)

Schneider Electric, one of the largest energy management solution providers in the world, has defined the smart grid as follows:

"*The Smart Grid combines electricity and IT infrastructure to integrate and connect all users (producers, operators, marketers, consumers, etc.) in order to continue to efficiently balance supply and demand over an increasingly complex network.*" (Schneider Electric, 2015)

The IEA (International Energy Agency) has defined the smart grid in 2011 as follows:

"A smart grid is an electricity network that uses digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end-users. Smart grids co-ordinate the needs and capabilities of all generators, grid operators, end-users and electricity market stakeholders to operate all parts of the system as efficiently as possible, minimizing costs and environmental impacts while maximizing system reliability, resilience and stability." (IEA 2011)

While there are different interpretations about what smart grid applications should be pursued in the development of a smarter electricity grid, the main idea is similar in the end: Connecting all electricity market stakeholders with advanced technologies, in order to operate the system as efficiently and reliably as possible.

2.2 Motive for smart grids

The entire energy industry policy is highly driven by climate change. In order to tackle this global problem, the entire energy sector has to adapt. This development has put the electricity networks under pressure to change as well. The motives for smart grid technologies are both external to the distribution network, like preparing for a low-carbon future, as well as internal, like the need for replacement of an ageing network infrastructure. One of the biggest external drivers for Finnish energy policy originates from European Union's Energy and Climate Package. The policy targets do not directly push forward smart grid technologies, but smart grid technologies are necessary in order to achieve the future power system the climate package is pursuing. (Hashmi 2011)

The Climate Package states the following targets for the year 2020 (compared to 1990):

- 20 % reduction of greenhouse gas emissions
- 20 % of renewable energy sources in the EU 27 energy mix
- 20 % reduction in the primary energy used (European Parliament 2009)

The Climate Package These reduction targets take into account transport, heating, lighting and electricity. For the electricity generation, the reduction target is even more ambitious: 35 % of all electricity should be generated with renewable energy sources in 2020. On top of that, heating and transportation is expected to affect the electricity demand profile in the future, when heat pumps and electrical vehicles become more popular. (Hashmi 2011)

The changing power system requires electricity networks to be significantly more flexible than they currently are. Renewable energy sources, such as solar and wind power, generate intermittent electricity, which means that it becomes more difficult to maintain the balance between supply and demand. On top of this, governments are setting standards that are more ambitious regarding system reliability. Aging infrastructure, increase in intermittent electricity generation, possible change in electricity demand profile and the strict governmental reliability standards are all serious challenges for Finnish DSOs.

In the future, one of the biggest technological challenges for distribution networks relates to controlling the energy flows of distributed intermittent energy generation. Increasing wind and solar power capacity sets certain technological requirements for the grid. When distributed generation is added to the distribution network, the need for grid improvements is often necessary. The requirements include better control and monitoring of the power system. This allows DSOs to manage demand, operate the existing assets more efficiently, and to utilize electricity storage. (Hashmi 2011)

The increase in intermittent power production has already affected the Nordic power system. The frequency fluctuations in the grid, which are caused by the imbalance in supply and demand, have already increased. As we can see in *Figure 1*, the trend in quality of frequency in the Nordic power system puts pressure to change for all stakeholders involved in the power system. For distribution companies, this means more control and monitoring capabilities to the MV and LV network. (ENTSO-E 2013)

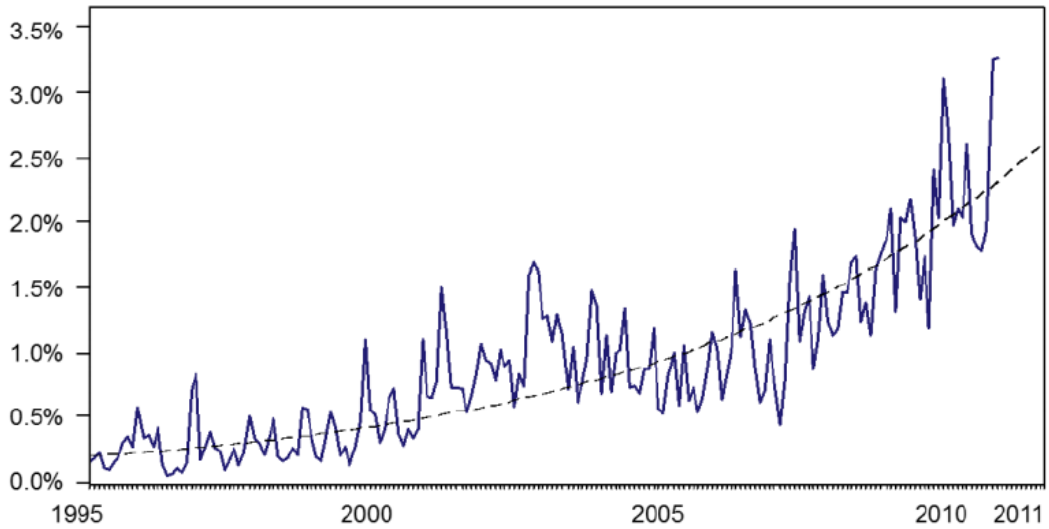

Figure 1: Quality of frequency in the Nordic Power system. The percentage is the relative time the system's frequency has been outside the normal frequency limit (49,9 - 50,1 Hz) (ENTSO-E 2013)

2.3 Difference between a smart grid and a conventional grid

When comparing a future smart grid to a conventional grid, the conventional grid is usually described as a grid with large conventional power plants feeding power to the transmission grid. From transmission grid, power is distributed downstream to the customers, without any flexibility or communication along distribution process. The concept of a conventional power system is illustrated in *Figure 2*.

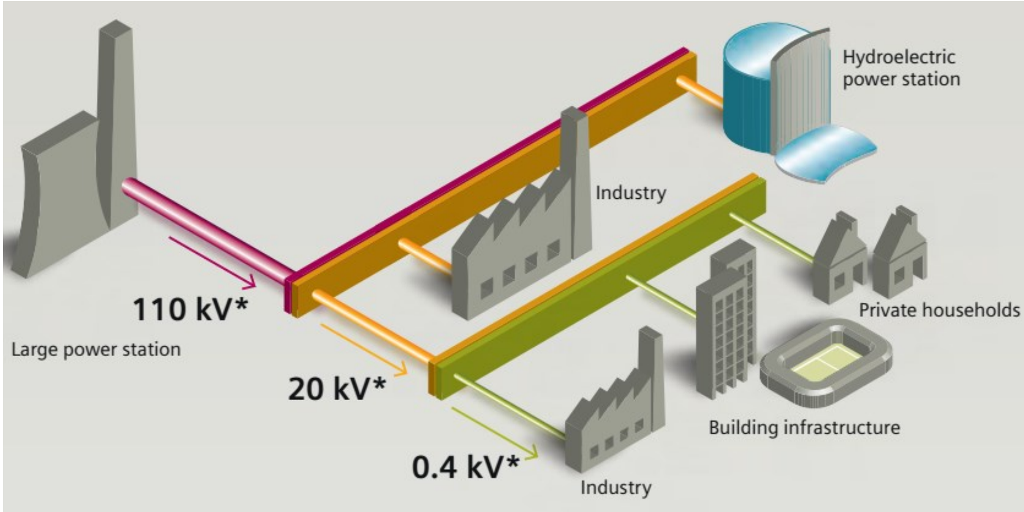

Figure 2: Illustration of a conventional power system (Siemens)

Figure 2 illustrates the future electricity grid, where different stakeholders are interacting with each other with bi-directional flow of energy and data. The future power system will also have more decentralized electricity production, which includes solar power, small wind turbines, micro-CHP-plants and electricity storage. Also, electricity vehicles will change the power system significantly by replacing fuel consumption with electricity consumption. The transformation to electric electricity powered transportation can be challenging, regarding the management of peak loads, but electric vehicles could also be utilized as electricity storage, for balancing the peak loads. The whole smart grid concept is illustrated in *Figure 3*. (Schneider Electric 2015)

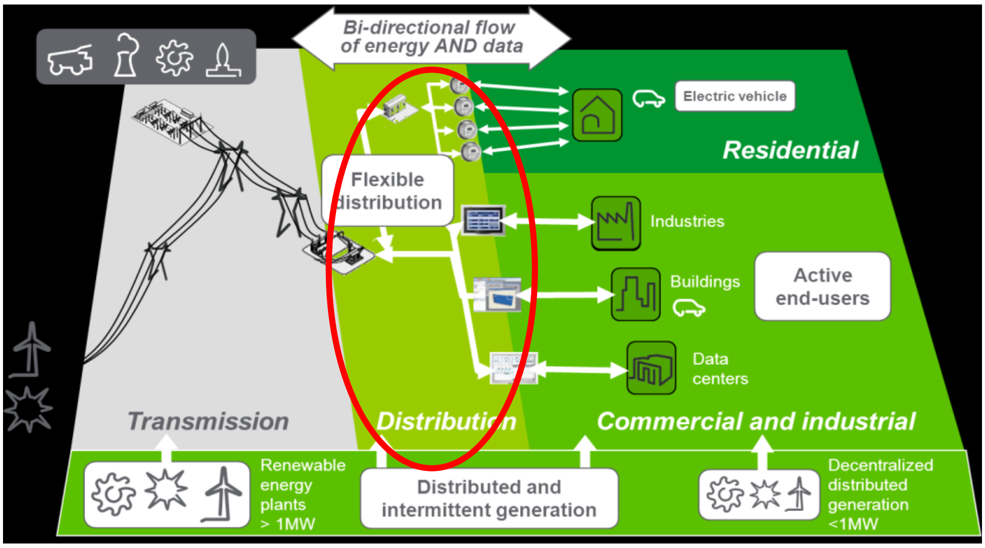

Figure 3: The smart grid concept. Inside the red circle, is the focus area of this thesis (Schneider Electric 2015)

In *Table 1*, the biggest differences between a conventional grid and a smart grid have been listed, through the operating environment, the opportunities the smart grid brings and the technologies and services it provides.

	Conventional grid	**Smart grid**
Operating environment	National and closed electricity market	International and open electricity market
	National policies and legislations, EU's influence	Policies and legislations on the EU level, global influence
The opportunities of the smart grid	System reliability	System reliability
	Efficient electricity production	Efficient electricity consumption
	Utility driven system, one-way communication between producer and consumer	Producers more involved, two-way communication between producers and consumers
Technologies and services	Centralized production (mostly)	Increasing de-centralized production
	Non-renewable energy sources and hydro power (mostly)	Diverse mix of renewable and CO_2-free energy sources
	Insignificant electricity storage	Increasing electricity storage
	Demand response only with big industrial end users	Demand response on residential customer level as well
	Manual meter reading after the electricity has been consumed	Real time consumption data wirelessly transferred to a control center
	Operation and maintenance (O&M) where the components are located	O&M remotely from a control center

Table 1: The difference between a conventional electricity grid and a smart grid. (A. Sarvaranta 2010)

As it has been stated earlier, the smart grid concept is a continuous evolution process, where existing and new technologies are slowly integrated to the grid in order to improve the properties of the existing distribution network. The technology for building a smarter power system already exists. At this point, it is mostly dependent on finding the most cost effective solutions and business models for the new smart technologies. The current status of smart grids varies between countries, but the goals and desired network properties are the same, in general. The current distribution network in Finland already utilizes some of the applications described in *Table 1*. (IEA, 2015)

This thesis is focusing on smart grid technologies that benefit the Finnish electricity distribution companies the most. More precisely, the focus point will be in MV lines and secondary substations. From distribution network's point of view, the biggest economic benefit can be realized when improving system reliability. Improved asset management and network operation optimization are also bringing value to DSOs. (IEA 2015)

3 Smart Grid trends

3.1 Demand response

Demand response (DR) is one of the biggest trends driving the development of smart grid technologies. It affects the entire electricity market, such as producers, distributors, consumers and electricity retailers. In this thesis, demand response is being discussed from the entire electricity market's point of view, not just distribution network's point of view. DR is an action where consumers can intentionally shift their electricity consumption load in response to changes in electricity prices either over time or in response to an incentive payment. Incentive payments are designed to lower electricity usage at times when demand is high or when system reliability is jeopardized. In a conventional electricity market, only supply has been controllable and demand has just been what consumers happened to consume. DR will increase the efficiency of the electricity market by allowing flexible demand. (Albadi & El-Saadany 2008)

Because there has to be constantly a balance between supply and demand in the power system, DR has potential to cost effectively balance to system, when supply and demand levels change rapidly and unexpectedly. Reasons for unexpected changes in the power system could be outages caused by generation malfunction, a fault in transmission or distribution grid and sudden load changes. Even though DR increases the efficiency of the power system, it does not mean less consumption. The system efficiency comes from consuming the electricity on low demand times, rather than a high demand times. The major technological requirements for demand response are an hourly measured smart meter and some energy management system to control electrical devices (Sarvaranta 2010). (Albadi & El-Saadany 2008)

3.1.1 Different demand response programs

DR programs can be divided into two main categories: Price Based Programs (PBP) and Incentive Based Programs (IBP), which is further divided into market-based programs and classical programs. The two categories include various different DR programs, which are represented in *Table 2.* Sometimes the two main categories are named price- and system-led programs. (Albadi & El-Saadany 2008)

Incentive Based Programs (IBP)		**Price Based Programs (PBP)**
Classical programs	• Direct Load Control • Interruptible Programs	• Time of Use • Critical Peak Pricing • Extreme Day Pricing • Real Time Pricing
Market based programs	• Demand Bidding • Emergency DR • Capacity Market • Ancillary services Market	

Table 2: Classification of DR programs (Albadi & El-Saadany 2008)

In classical IBP, participating customers receive participation payments, usually as a bill credit or discount rate, for their participation in the programs. In market-based IBP programs, participants are paid according to their performance, depending on the amount of consumption reduction during critical conditions. (Albadi & El-Saadany 2008)

Direct Load Control IBP program allows utilities to remotely shut down participant's electrical equipment without separate permission of the end-user. This IBP program requires remotely controlled devices at the participant's end. Direct Load Control programs are usually considered only for residential customers with high electricity consuming devices, such as water heaters and air conditioners. These programs may cause temporary loss of living comfort amongst participants. (Albadi & El-Saadany 2008)

Interruptible Programs differ from direct load control programs by letting the participant to reduce their load by themselves to predefined values. If they cannot respond to this, participant can face penalties, depending on the program's terms and conditions. (Albadi & El-Saadany 2008)

In **Demand Bidding Programs** customers bid on specific load reductions in the electricity wholesale market. A bid gets accepted if it is below the market price. If a bid is accepted, the participant must limit his load by the amount specified in the agreement or face penalties. (Albadi & El-Saadany 2008)

In **Emergency DR programs**, participants are paid incentives for measured load reductions during emergencies, where the incentive value is formed by other participants' bids. (Albadi & El-Saadany 2008)

Capacity Market Programs are offered to customers who can commit to providing load reductions with a short notice (usually day-ahead notice) when system emergencies arise. (Albadi & El-Saadany 2008)

Ancillary Services Market programs allow customers to bid on load reduction in the spot market as operating reserve. If the bid is accepted, the participant pays the market price for committing to be on standby in case an emergency occurs. The participant gets an additional payment, based on the market price, if the load reduction is actually needed. (Albadi & El-Saadany 2008)

PBP programs are based on dynamic pricing rates in which electricity tariffs are not flat; the rates fluctuate following the real time cost of electricity. The objective of PBP programs is to flatten the demand curve by offering a high price during peak periods and lower prices during off-peak periods. These rates include the Time-of-Use (TOU) rate, Critical Peak Pricing, Extreme Day Pricing, Extreme Day CPP, and Real Time Pricing (RTP). (Albadi & El-Saadany 2008)

One of the most common types of PBP is the TOU rates, where the rates of electricity price differ in different blocks of time. The rates are higher during high peak demand periods. Usually there are two time blocks in TOU programs; the off-peak rate and the peak rate. In RTP programs, customers are charged hourly fluctuating prices reflecting the real cost of electricity in the wholesale market. RTP participants are informed about the prices on a day-ahead or hour-ahead basis. Many economists are convinced that RTP programs are the most direct and efficient DR programs suitable for competitive electricity markets and should be the focus of policymakers. (Bloustein 2005)

3.1.2 The benefits of demand response

For participating consumers, DR benefits them by reducing their electricity bill or through incentive payments, depending on whether it is an incentive or a price based DR program. (Albadi & El-Saadany 2008)

For the environment, DR is expected to decrease total greenhouse gas emissions. The reduction is expected to happen by satisfying peak demand with decreasing consumption, rather than generating electricity with fossil fuel power stations. (Jokiniemi 2014)

For the whole electricity market, DR is expected to reduce the total electricity price on the market. The price reduction is expected to happen through more efficient utilization of available resources. DRs long-term effects on the total electricity market include avoided upgrades and infrastructure enforcements for distribution and transmissions networks. All the avoided costs will eventually be reflected in the price of electricity for all consumers. (Albadi & El-Saadany 2008)

Another major improvement for the whole electricity market is the reduction of price volatility. Usually a small reduction of demand can lead to major reductions in price of electricity. This phenomenon happens because electricity generation costs often increase exponentially near maximum generation capacity. DR's potential effect on electricity market price is illustrated in *Figure 5*. (Säntti 2015)

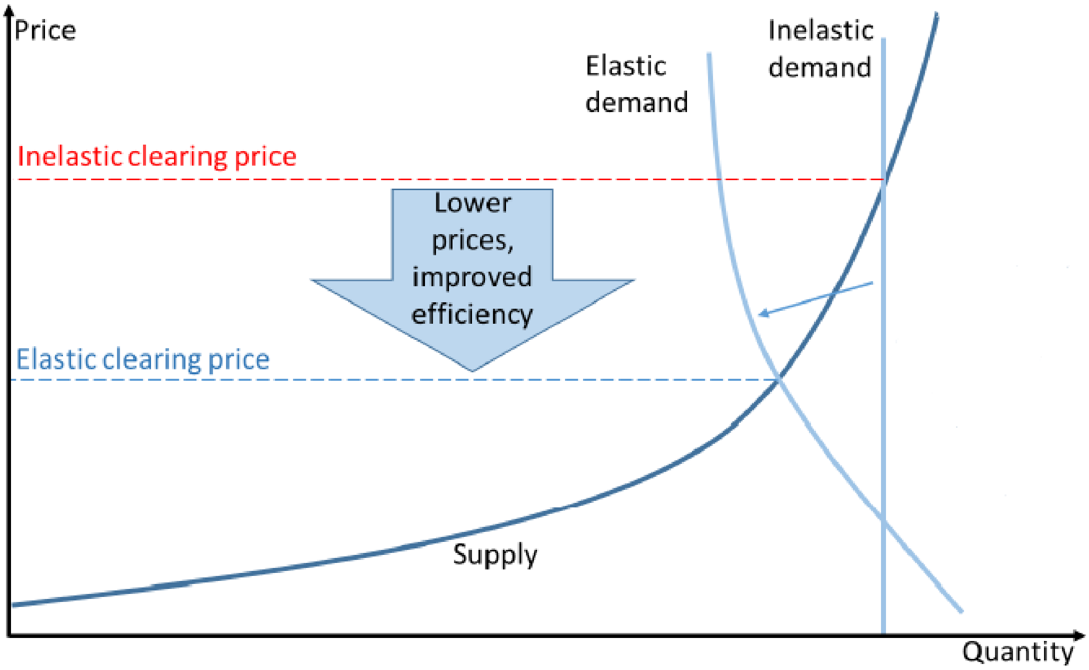

Figure 5: DR's potential effect on electricity market price. (Säntti 2015)

3.1.3 Demand response in Finland

There are four different market places for demand response in Finland: *Elspot*, *Elbas*, balancing power market, reserve markets. *Elspot*, the day-ahead market, and *Elbas*, the intraday market, are both operated by the Nord Pool Spot. Reserve markets can be divided into further categories, based on the response time and capacity. (Jokiniemi 2014)

In Finland, balancing power market and reserve markets have concerned mostly large industrial customers in forestry and the metal and chemical. *Fingrid* is responsible for maintaining the power balance and reserve markets. If a large industrial consumer wants to participate in the reserve markets, it has to make a balance service agreement with *Fingrid*. Balancing power market acts as a market place for balancing bids[1]. Residential consumers have not been able to access reserve markets or power balance markets, mainly because of the required minimum power output available. (Jokiniemi 2014)

Electricity whole sellers in Finland have long provided a billing system for residential customers, where electricity price has been two sided: lower price at night time and higher price at day time. This simple TOU program has allowed residential customer to shift some of their consumption to night time and thus save money. After smart meters were installed, residential customers have been able to participate more efficiently to DR through RTP. This participation only requires a smart meter, an electricity contract where billing is based on real-time electricity prices, and own activity. In RTP programs, the demand response effect

[1] Balancing bid is either an Up-regulating bid or Down-regulating bid. The bid contains the following information: power (MW), price (€/MWh), production/consumption, location and name of the resource. (Jokiniemi 2014)

comes from customers' own willingness to avoid consuming electricity when it is more expensive. (TEM 2008) (Sarvaranta 2010)

Finnish utilities have developed additional services for customer who are willing to follow their electricity consumption hourly. This increase of awareness will play a big role in RTP based DR programs for residential and commercial customers. For example, *Helen Oy*, energy utility operating in Helsinki, provides their customer the access to monitor their own electricity consumption by the hour. The service can help customers to plan their energy usage. The online service is called *Sävel Plus*. Other utilities in Finland provide similar services to residential customers. (Helen Oy 2016)

Other demand response programs for residential customers are currently emerging in Finland. One example is a virtual power plant for balancing the power system. In 2016, *Fortum Oyj* launched a pilot project with 70 residential customers with electricity heating system in their homes. In the pilot project, the 70 households participating in the pilot have given *Fortum Oyj* permission to momentarily lower the temperature of hot water tanks during peak electricity consumption periods. The virtual power plant creates a reserve that can be sold to the *Fingrid*, when balancing power is needed. Turning off the hot water tank temporarily does not have any impact on the use of hot water in the participating households. The virtual power plant is able reduce the demand on the electricity network's output by approximately 100 kilowatts. The virtual power plant concept with 100 participants is illustrated in *Figure 6*. (Fortum 2016)

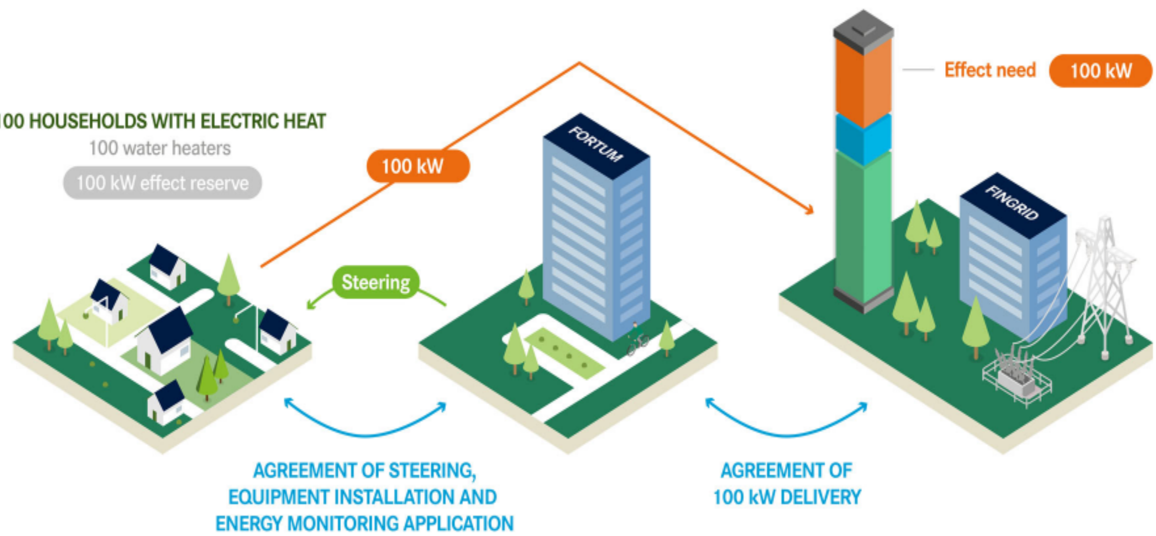

Figure 6: Virtual power plant concept by Fortum Oyj. (Fortum 2016)

3.1.4 Demand Bidding Program example in New York City

In 2016, a company in New York City called *Con Edison* held a Demand Bidding Program (auction) to its customers around Brooklyn area to get commitment to reduce energy demand during peak hours. The auction generated successful results, when Con Edison expects energy usage to drop by 22 MW in peak hours during summer of 2018. Con Edison accepted bids ranging from $215 to $988 per kilowatt per year. Con Edison has estimated that it will avoid the construction of a $1.2billion substation, because of the reduction of peak power demand. (Con Edison 2016)

These kinds of incentives based demand response programs are gaining momentum at a global level, especially in the U.S. The business model for incentive based demand response seems beneficial for all stakeholder involved. For the whole power system, it reduces energy consumption during peak demand times, for participants it lowers monthly electricity costs, and it provides a revenue stream for the service provider. Another positive factor in incentive based demand response is the fact that it usually requires a relatively small investment from consumers participating to the program. This positive factor applies to price based demand response programs as well, where consumers can manage their energy consumption without any initial investments. All that is needed for a simple PBP, is the access to monitor own electricity consumption and an hourly based billing contract.

3.1.5 DR challenges

From technical point of view, the biggest barrier for demand response for residential customers is the remote controllability of electrical equipment. Residential customer can manage their demand through by avoiding consumption during high hourly electricity prices, but larger participation through balancing bids or participating into reserve markets would require better remote controllability for consumption. In Finland, electricity retailers cannot control the loads of residential customers with a single software system, due to the lack of standardized load control signals between the retailer and the smart meter (operated by a distribution company). This compatibility problem makes it difficult to scale demand response services to residential customers. In the future, it is possible that load control happens through a separate device and smart meters are only used for measurement purposes. (Sarvaranta 2010)

The other barrier for large-scale demand response is the lack of knowledge among customers. Because demand response is based on customers’ willingness to change their consumption habits, they only can adapt demand response programs if they see that they can gain significant monetary benefits from it. (Sarvaranta 2010)

3.2 Distributed generation

Distributed Generation (DG) does not have a consistent definition, but the term is typically used to describe small-scale electricity generation within the distribution network or on the customer side of the network. DG also means that control of the generation is decentralized and not centralized, like in conventional power stations. Because there is not an official definition for DG, there is lack of data on how much DG is being utilized in Finland. DG is not necessarily a more efficient way the generate electricity compared to centralized generation, but it is expected to decrease greenhouse gas emissions through the use of renewable energy sources. (Vihanninjoki 2015)

Usually the following technologies are utilized in DG systems:

- Small scale wind power
- Solar power
- Small hydro power
- mini CHP
- Heat Pumps (Vihanninjoki 2015)

There are three different legislations in Finland, which defines DG in a different way. The law for (Finlex 1260/1996 2) the taxation of electricity generation defines ‘small scale generation’ as electricity generation, which generates less than 800 000 kWh of electricity per year. If the generation facility produces less, it does not have to pay the tax. This law was applied from first of May 2015. Electricity Market Act (Finlex 588/2013 3) defines ‘small scale generation’ as electricity generation, which has capacity of less than 2000 kVA. Environmental protection law (Finlex 527/2014) also mentions small-scale generation by demanding an environmental permit from a CHP unit with more than 50 MW of capacity. In this thesis DG means a small-scale renewable electricity generation, which is connected to the MV network (20 kV) or low voltage network (0.4kV). (Vihanninjoki 2015)

3.2.1 DG and the distribution network

Small DG units can be added to the low voltage network either through a separate connection point or behind the customer’s meter, parallel to the consumption point. Low voltage lines are capable of transferring up to couple of hundreds of kilowatts for couple of hundreds of meters. Larger (couple of hundred kilowatts) DG units can be added directly to secondary substations. The transfer capability of MV lines is related to the distance from the connection point to the primary substation upstream, but usually 20 kV lines can transfer couple of megawatts for 20 – 30 km. In Europe, only a small portion of DG is connected directly to the distribution network. The same situation is in Finland too, where every DG project that will be connected directly to the distribution network is treated and considered as a special case. (Vihanninjoki 2015)

In principle, the distribution network is design to transfer electricity one-way; from power plant to consumer. DG changes the dynamics of the low voltage network by adding more connection points that feed power into the network, which means that the direction of the current may change. It becomes increasingly more difficult to manage voltage levels, when the direction of the current changes. In addition, DG increases the residual current levels, which may force DSOs to invest in network reinforcements. (Sarvaranta 2010)

3.2.2 DG market situation and trends in Finland

According to Lehto (2009), there is much DG potential in Finland, but it has been shown that other countries' DG has increased significantly only when there have been government subsidies for DG. At the moment, there are no additional subsidies or tax cuts related to DG, except the three legislations related to the power capacity or produced energy, which were described earlier. Next, the current market situation and potential of solar power and small-scale wind power are described briefly. (Lehto 2009)

Solar Power can be dived into five different categories: portable devices (e.g. solar panel charged batteries), solar panels in off-the-grid locations (usually summer cottages), solar PVs in small residential buildings connected to the distribution network, large residential buildings, and industrial sized solar power plants. Finnish Funding Agency for Innovation (*Tekes*) has published a detailed market map from each of these five categories (Tekes 2013). There is no detailed data available on how much solar power is utilized in Finland, but it has been estimated that the total solar power capacity in Finland lies between 1MW - 3MW. The total revenue of solar power industry is estimated to be 10M€. The estimated number of solar panels in of-the-grid locations (mostly summer cottages) is approximately 40 000. (Gaia Consulting Oy 2014)

The trend for solar panels is positive. The number of solar panels connected to the distribution network has doubled in 2013 and the trend is expected to continue as such. The biggest reason for this trend is related to the price. The total solar panel system costs have dropped significantly in recent years, due to domestic competition between solar panel system suppliers and the global price reduction of solar panel components. (Gaia Consulting Oy 2014)

Small-scale wind power is defined as a wind turbine with less than 50 kW of nominal power. The technology can be divided into four different categories; summer cottage turbines (less than 1 kW, usually 200–400 W), turbines for commercial buildings (less than 5 kW), turbines for large companies and agriculture (5–50 kW), and turbines for telecommunication towers (some kilowatts). The number of wind turbines delivered to summer cottages (less than 1 kW) lies between 100–200, whereas the number of turbines delivered for commercial buildings and telecommunication towers is somewhere around 10 for both categories. Approximately only one wind turbine is delivered for large companies and agriculture (5–50 kW) annually. As we can see, small-scale wind power market is fairly small and majority of the turbines are for summer cottages. (Gaia Consulting Oy 2014)

The market trend for small-scale wind power has been steady for a while and the number of delivered turbines has stayed relatively constant during the current decade. There are estimations for market growth in specialized off-grid wind turbines for telecommunication towers and electricity storage systems. There is also market growth potential in solar and wind hybrid systems in off-grid locations. Both of these estimations are based on on-going R&D projects. (Gaia Consulting Oy 2014)

It seems that the only potential for future small-scale wind power lies in specialized off-grid systems and telecommunication towers. It is notable to mention that this market trend does not take into account bigger turbines (over 50 kW) and wind farms.

3.3 Challenges for smart grid development

Smart grid technologies will bring undoubtedly multiple benefits to all stakeholders involved in the electricity market, but there is always a variety of challenges to slow down the implementation of these technologies. There has been conducted different kind of surveys relating to the readiness of the energy industry and consumers for the smart grid technologies. In 2009, there was a survey that was conducted to network utility leaders in California, USA. The survey named cost as the strongest barrier for implementing new smart grid technologies for their organization. The results of the survey can be seen in *Figure 7*. Even though the survey was conducted in the USA, it is safe to assume the same challenges for market implementation may apply in Finland as well. (Hashmi 2011)

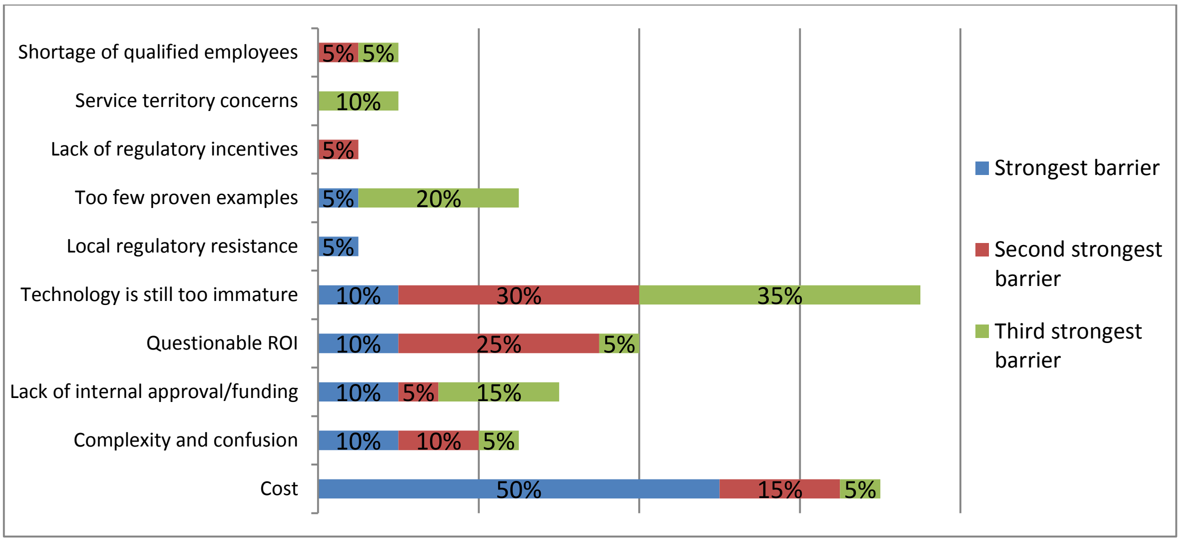

Figure 7: Biggest barriers for smart grid implementation (Gulich, 2010)

3.3.1 Regulatory challenges

The installment of smart meters and other measurement devices throughout the distribution network are bringing challenges in component compatibility. A big challenge in many countries is the integration of the new components with existing components and software systems. This challenge is based on the fact that there is not always universally accepted protocol for control, communication and interfaces. Even though there are standards on the compatibility of the physical network components, there is still need for more standardization, for example a requirement that would ensure a common communication vocabulary among system components. One example in Finland, is the lack of standardized communication protocol related to the remote controllability of smart meters. (Farhangi 2010)

3.3.2 Cyber security and privacy

With all the benefits smart grid technologies are bringing to the utilities and customers, there is an increasingly challenging threat emerging: Cyber security and privacy. Increasing utilization of ICT will provide various ways to improve the system, but it also opens new ways for unwanted parties impacting the system. According to the US Department of Homeland Security, 53 per cent of cyber security incidents reported and investigated by the agency in the first half of 2013 were related to the energy industry. This is why utilities and technology providers have to consider implementing more reliable ICT systems in order to ensure the future safety of the power system. (Schneider Electric 2015)

One example of cyber threat in the distribution network is within substations. Sensitive information (such as online documentation that describes how these devices work) about the proprietary devices in substations can be nowadays accessed via internet. Another cyber threat example is a cyber-attack on distribution network's monitoring and operating software (SCADA). There has been an example case in the US in 2010, where a cyber-attack disabled an entire SCADA system for two weeks, causing massive financial losses to the distribution company. (Schneider Electric 2015)

The other similar concern is emerging from the increasing amount of customer data available. The deployment of smart grid technologies in the customer end might face opposition from end-users regarding issues associated with data sharing and ownership. Personalized consumption data is sensitive information. Customers' data and privacy must be secure in order for a smart grid to be considered as a success. (IEA 2015)

After smart meters were first installed and public's awareness for customers' personalized consumption data became available, number of standards has been published. For example, Advanced Metering Infrastructure Security Task Force (AMI-SEC Task Force), alongside with The NIST's (National Institute of Standards and Technology) Cyber Security Coordination Task Group, has presented security concerns relevant to smart metering and provided guidance and security control to organizations developing or implementing smart meter solutions for the smart grid. (ASAP-SG 2009)

4 Overview of the technologies used to operate the Finnish distribution network

4.1 Background

The Finnish distribution network's primary function is to deliver electricity from the transmission grid to end-users. The distribution network is being managed, operated and supervised at many different levels, as seen in *Figure 8*. The data from the distribution network is collected at the customer, network and the substation level by various types of measurement devices, where it is transferred to a centralized control center, where it can be utilized for operational and planning purposes. The pyramid hierarchy illustrates the number devices used in the different levels of the distribution network. The data volume increases downstream of the distribution network, as well. The different information systems mentioned in *Figure 8* are not tightly tied to the levels. An information system might be utilized by many stages by different DSOs. (Hälvä 2013)

This chapter will first describe briefly what parts of the power system is considered the distribution network. After this, the different information system technologies are described, which include software, IEDs (Intelligent Electronic Device), RTUs (Remote Thermal Unit) and the interconnection between these. Sometimes the term information system refers only to a software system, but in this thesis, the term information system refers to the whole entity, which includes all four parts mentioned above. There are variations for example which software systems are utilized in the electricity distribution process, but the main functionalities are somewhat the same. (Hälvä 2013)

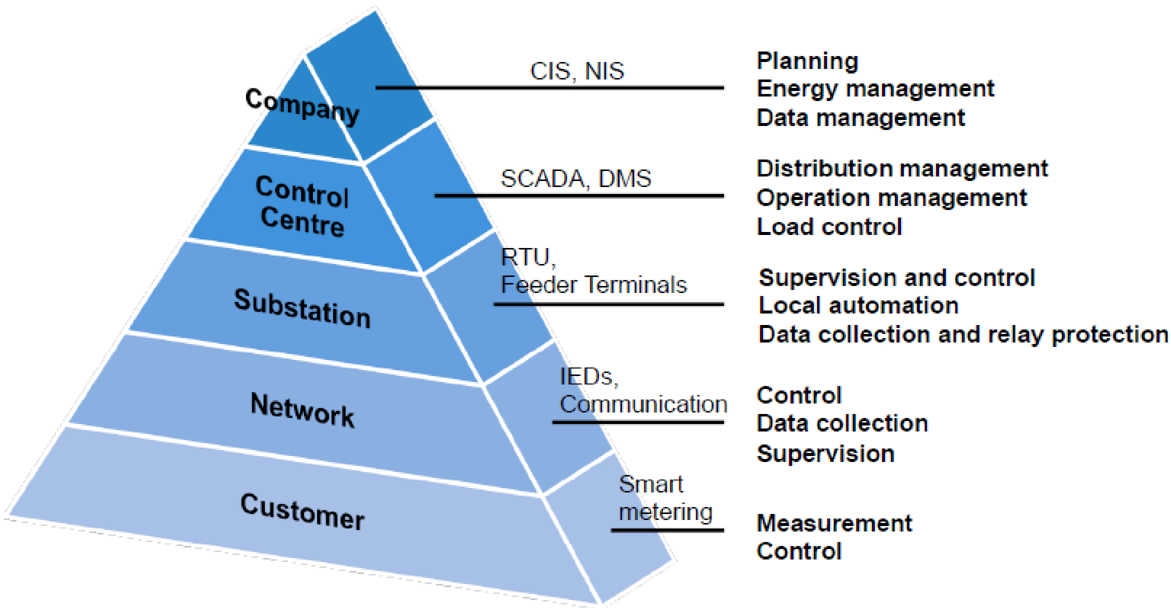

Figure 8: ABB's portrayal of the information system hierarchy in a Finnish distribution network. (Hälvä 2013)

4.2 Description of the Finnish distribution network

The Finnish power system consists of power generation, transmission grid, regional networks, distribution networks and electricity end users. The power system in Finland is part of the inter-Nordic power system together with the systems in Sweden, Norway and Eastern Denmark. There are also direct current transmission lines to Finland from Estonia and Russia. In addition, the whole inter-Nordic power system is connected the Continental Europe's power system with direct current transmission lines. (Fingrid 2016)

Fingrid is responsible for the functioning of the Finnish electricity transmission grid. The transmission grid is the high-voltage trunk network, which covers the entire country. Major power plants, industrial plants and regional electricity distribution networks are connected to the transmission grid. *Fingrid* is responsible for system supervision, operation planning, balance service, grid maintenance, construction and development, and promotion of the electricity market in the transmission grid. (Fingrid 2016)

The whole electricity distribution process starts from a primary substation, which is connected to the transmission grid. Downstream from the primary substation, electricity is distributed along the MV lines all the way to the secondary substations, or to an industrial or a commercial customer. From the secondary substations, electricity is distributed to rest of the customer along the low voltage lines. This thesis is going to focus on the MV part of the distribution network. The customers that are connected to the distribution network can be divided onto four categories: residential, industrial, public service, commercial. (Siirto et al. 2011)

The Finnish distribution network is owned approximately by 80 different distribution utilities (Energy Authority 2016a), which have regional responsibility (monopoly) to operate the MV (20 kV) and low voltage (0.4 kV) systems in Finland. Some utilities operate only within one city (e.g. Porin Energia and Helen Sähköverkko), and some cover large parts of Finland (Caruna and Elenia). A part of a Finnish distribution network is illustrated in *Figure 9.* (Millar 2016) (Lakervi & Partanen 2009)

The electricity distribution companies operate the following parts of the Finnish power system:

- Regional network 110 kV
- HV/MV primary substations 110/20 kV (110/10 kV)
- MV power distribution 20 kV (10 kV)
- MV/LV secondary substation 20/0.4 kV
- Low voltage network 0.4 kV
- Industrial network 20, 10, 6, 3, 0.6, 0.5, 0.4 kV (Millar, 2016)

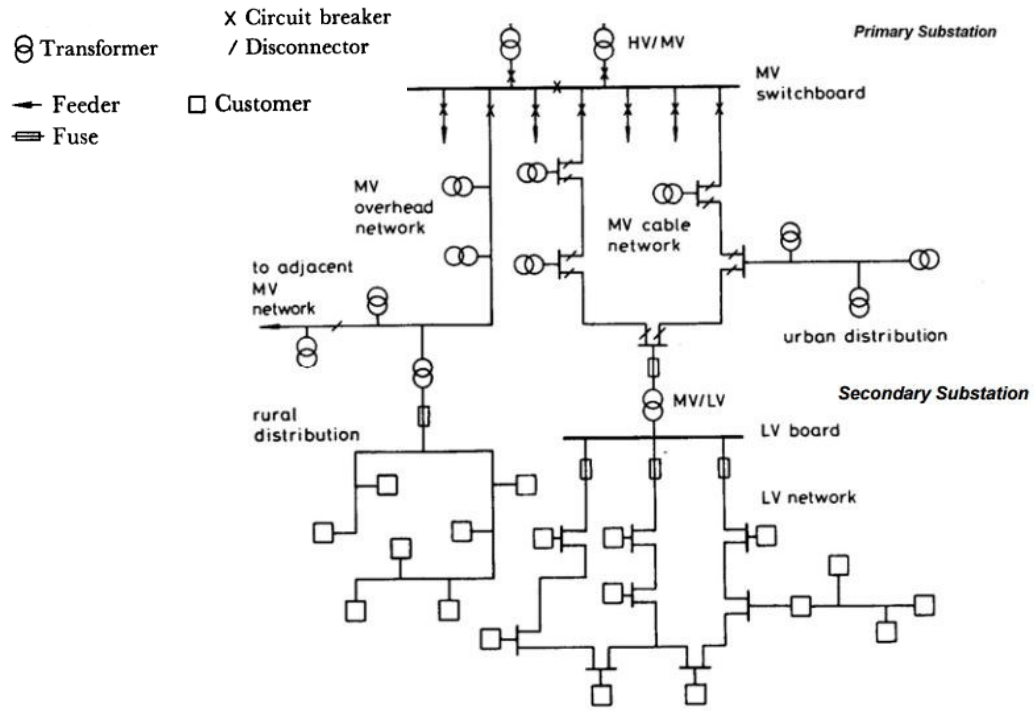

Figure 9: Illustration of a Finnish distribution network. (Millar 2016)

The structure of the distribution network is often built as a loop, but under normal operating conditions, the loop is open at a certain point. At the electrical point of view, the network is operated as a number of radial feeders. This configuration offers a back-up possibility if a fault occurs between an isolation point and an open point. In rural area, it is common to have a purely radial configuration without back-up interconnections, especially in low voltage networks. Ring topologies are becoming more common while distribution automation (substation and feeder automation) technologies are becoming more feasible for utilities. (Lakervi & Partanen 2009)

4.3 Distribution network management at company level

DSOs have to make constantly long-term decisions relating to asset management, customer satisfaction, reliability assessment, risk assessment etc. These decision makers use various types of information systems to support the decision making process. Most commonly used software systems in Finland for long term network planning and other management decisions are Geographical Information System, Customer Information System and Automatic Meter Management system.

4.3.1 Geographical Information System

Geographical Information System (GIS), sometimes referred as the Network Information System (NIS), is a software system that contains information about the physical characteristics of the network components. Physical characteristics include the component's technical information, physical location of the components and economic values about the components. The GIS system is mostly used as a supportive tool in asset management. The values, that are stored in the information system, can be utilized when DSOs design the distribution network and optimize the life time value of their network components. (Schneider Electric 2015)

4.3.2 Customer Information System

Customer Information System (CIS) consists of wide range of different functions related to customer management. CIS is often referred as a Customer Relationship Management system. The systems main objectives are storing customer activity data, customer service, management of contracts and billing. Before smart meter were installed, CIS was also used to collect and store consumption data, which was used for customers' load estimations. Advanced Meter management system took the responsibility of storing and analyzing the consumption data, after the smart meters were installed in Finland. (Harjula M. 2008)

4.3.3 Automatic Meter Management

Automatic Meter Management (AMM), also referred as Meter Data Management System, is a software system for managing metered consumption data, which can be used throughout the utilities and shared with customers, partners, market operators and regulators. AMM system is a key software component of Advanced Meter Infrastructure. The data used in an AMM system consists primarily of consumption data. The software system that collects the consumption data from the smart meter is often referred as an Automatic Meter Reading system. (Harjula M. 2008)

4.4 Distribution network management at control center level

DSOs have to make constantly operational decisions in the distribution network, related to distribution management, outage management, load control, and other controllability related tasks. The information systems used for decisions mentioned above, are based on real-time data gathered from measurement devices located in the substations and other network components. The most common software systems used in a control center are SCADA, DMS and OMS. The three software systems are sometimes integrated with each other, into one integrated software system. The interconnections of the information systems in a typical Finnish distribution network are illustrated in *Figure 10*. (Hälvä 2013)

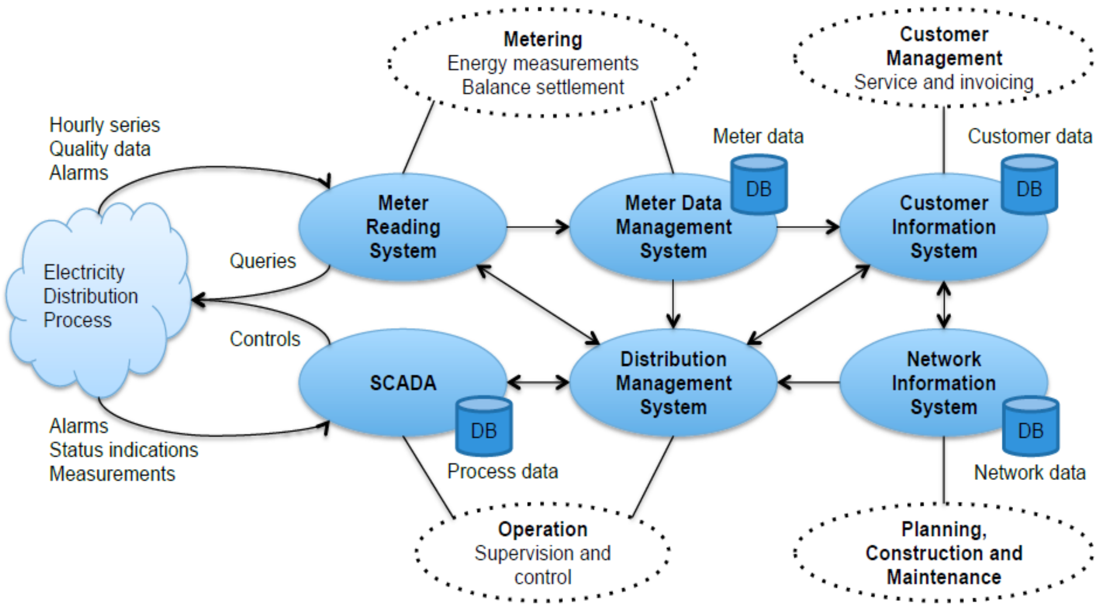

Figure 10: The Interconnections between information systems in the distribution network. (Hälvä 2013)

4.4.1 SCADA

Supervisory Control and Data Acquisition (SCADA) is a centralized software system, which is used to operate the electricity distribution network. The systems main objectives are controlling and monitoring in real time the distribution network process. Controlling and monitoring requires two-way communication between substations and a control center. In more detail, the SCADA system gathers data from various sources along the distribution network, preprocesses it, displays it at the control center and stores it to a database. After this, the data is accessible for operational purposes and other information systems. The real-time operational tasks are executed by sending control signals from the control center to the substation. The whole information system consists of remote thermal units (RTU) and Intelligent electric devices (IED) located in substations, a centralized operating system and telecommunication between these three. (Venkatesh et al. 2004)

4.4.2 Distribution Management System

Distribution Management System (DMS) is a centralized software system, which is used by a distribution operator as a supportive tool for decision-making. The main purpose of the system is to produce real-time supportive information to support the operation of the distribution network. DMS imports data from other information systems and combines them together, in order to create supportive information for the DSOs. (Lakervi & Partanen 2009)

The main purpose of the DMS system is to process data from GIS and SCADA systems. The system allows the decision makers to make calculated decisions based on real-time and a static view of the distribution network. Data imported from GIS is used to produce a static model of the network. This data consists of physical information about the network, such as location and characteristics of the components. Data from SCADA is used to create a real-time model of the network. By combining these two models, DMS creates a dynamic model, which shows the topological and electrical state of the distribution network. (Lakervi & Partanen 2009)

4.4.3 Outage Management System

Outage management system (OMS) is centralized software system that helps DSOs manage outages. With the help of SCADA, OMS can be implemented with real-time data awareness of the entire distribution network. Instead of pre-engineered solutions, DSOs can make all their decisions based on the current state of the network. When a fault occurs, the centralized software system can determine optimal switching routes that can restore power the maximum number of customers, while considering priority customers (e.g. hospitals). When talking about software systems that are used for restoring outages in the distribution network, DMS is sometimes referred as the outage restoration software. In these cases, the OMS properties are in integrated to the DMS.

OMS plays a big role in fault location. Before smart meters were installed, the OMS combined the data collected from the substations, fault location devices and customer outage reports. Nowadays OMS is processing smart meter data instead of customer calls in order to localize the fault in the low voltage network. When combining the data from SCADA (substation activity data), fault location devices and smart meters, locating the fault takes less time (Gauci 2013). Improving system reliability with smart grid technologies will be discussed more in *Chapter 5*.

OMS can utilize historical weather data in a post-fault analysis. Because different weather conditions can cause different types of system interruptions, DSOs can better prepare themselves for different types of component failures. Weather forecast based outage predication also helps utilities to inform the media and customers about current outages and the possibility of upcoming outages. (Chen 2014) (Gauci 2013)

4.5 Substation and feeder automation

Distribution network automation consists of network components RTUs, IEDs, control center and secure communication. The biggest benefit automation brings to the DSOs is the improvement of system reliability. The automation process can be dived into two categories: substation automation and feeder automation. Substation automation enables electric utilities to remotely control, monitor, and coordinate the distribution components installed in primary substations, typically breakers, switches, transformers, and load tap changers using IEDs and RTUs, such as sensors, meters, protection relays, and controllers. Some of the primary substations can be controlled remotely with a SCADA system from a centralized control center, whereas RTUs are in the substation collecting telemetry data and sending it to the control center. This telemetric data can be utilized with the DSM and other software systems. According to the data collected by the Energy Authority (2016a), in 2014, all distribution companies owned approximately 870 primary substations in Finland. (Schneider Electric 2015)

Feeder automation extends to circuits, disconnector stations and secondary substations beyond the primary substation. It typically includes re-closers, sectionalized switches, capacitor banks, voltage regulators, and fault indicators, and their associated monitoring and control equipment capable of communicating with SCADA/DMS systems. Feeder automation technology is not as much utilized as substation automation by DSOs. Feeder automation technology will be discussed in more detail in *Chapter 6*. (Schneider Electric 2015)

There is no data available for Finnish distribution network's level of automation at primary substations and secondary substations. In this thesis, the automation levels of secondary and primary substations will be researched by interviewing major distribution companies in Finland. This will not represent the entire Finnish distribution network, since there are approximately 80 different companies operating in Finland.

4.6 Advanced Metering Infrastructure

Advanced Metering Infrastructure (AMI) offers end-users, energy producers, regulators and network operators multiple useful tools and services enabling the smarter use of energy. In this thesis, the term AMI is used to describe a smart metering system. AMI involves the deployment of a number of technologies, such as automatic meter reading system, AMM system and smart meters. The technologies used in AMI vary depending on the country and market conditions, but the main functionalities can be described as follows:

- Remote consumer price signals, which can provide time-of-use pricing information.
- The collection, storing and reporting personalized consumption data for any required time intervals
- Better energy consumption analysis from more detailed load profiles.
- Ability to help locating outages remotely by sending a signal when meter goes out and when power is restored.
- Remote connection and disconnection of power
- Ability to detect losses and theft.
- More effective cash collection and debt management for retail energy service providers. (IEA 2011)

The European Smart Meters Industry Group (ESMIG) defines four functionality requirements for a smart meter: two-way communication, remote reading, support for advanced tariff and payment system, and remote connection and disconnection of power (IEA 2011).

In a conventional grid, without AMI, the utilities have usually collected consumption data manually. Consequently, utilities have had a lack of quality data on the consumption of their customers. This lack of data limits the frequency and accuracy of consumers' bills (ESMIG

2009). This conventional billing system, which is based on consumption estimates and balancing bills, may cause confusion with the customers, if their consumption estimates have notably differed from their actual consumption.

AMI allows the customers to gain more insight into their energy consumption and provide tools to encouraging customers to better manage their energy. This increase in awareness is one of the key motives behind the smart meter installment. The more accurate the available consumption data is for the customer, the easier it is to manage his/her own energy consumption.

In Finland, AMI infrastructure is based on an hourly measured electricity meter, which allows remote reading and hourly based billing. Majority of smart meters were installed between 2008 and 2013. In 2014, 95 per cent of consumers had a smart meter installed in their homes (Taloussanomat 31.10.2014). The Finnish smart meter also allows the consumer to monitor his/her consumption in real time by buying an additional electricity consumption-monitoring device.

The European Commission is planning to set a standard on the smart meter's measurement time interval, by the year 2019. Instead of one hour, as we have in Finland, The European Commission is preparing to set a standard, which requires the AMI to measure customers' consumption in 15-minute intervals. If this standard is going to be applied, Finnish distribution companies have to make major investments to adapt this new smart meter requirement. The Energy Organization (*Energiateollisuus ry*) has estimated that one-fourth of the current meters (even though almost every meter is already a 'smart meter') will have to be replaced. The rest can be adjusted with a software update. *Paikallisvoima ry* estimates the total costs to be 100 to 150 euro per customer. The motive for setting a standard, which requires 15-minute measurement interval, is the increase of variable renewable energy generation. A shorter time interval in beneficial for the power system, because the electricity generation profile varies progressively when more intermittent solar and wind power production is connected to the grid. (Yle 2016)

5 Government and the EU driving the smart grid development

5.1 Operational environment in Finland

In Finland, the electricity distribution business is a natural monopoly, which means that there is no local competition between distribution companies and that the business itself is highly regulated. The most important regulation is to ensure that the pricing stays reasonable for the customers. To ensure that the regulation is impartial, there has to be unbiased third party regulator. The Energy Authority acts as the regulator for distribution companies in Finland. (Heikkilä 2013)

In 2015, there were 79 different electricity distribution companies operating in Finland (Energy Authority 2016a). The biggest legislative factor influencing the business of these 79 distribution companies is the *Electricity Market Act* that was approved by the parliament of Finland in 2013. This act sets ambitious targets on system reliability. The Energy Authority has been signed to supervise that the distribution companies will fulfill these requirements mentioned in the act. This chapter will take a closer look on these requirements, mentioned in the Electricity market act. (Energy Authority 2013)

The Energy Authority published a new regulation model for years 2016 – 2023, in 2015. The regulation model defines the network value and incentives of the distribution company. The network value defines how much turnover the company can make. Prior, one regulation model was renewed every four years, in contrast for the eight years for the new regulation model. This regulation model has high effect on the investment behavior of the distribution companies, which directly affects what technologies or measures distribution companies invest in, in order to reach reliability targets. In *Chapter 5.3*, the regulation model is discussed in more detail, focusing on the relevant reforms made to the new regulation model. (Energy Authority 2016b)

5.2 Electricity market act (2013)

The most influential legislation affecting the development of the Finnish distribution network is the *Electricity Market Act.* This legislation came into effect on first of September 2013. *Electricity Market Act*'s main requirement is related to maximum outage duration. When the requirements are coming to effect, the *Energy Authority* will be responsible for supervising the distribution companies that they will reach these targets. If it seems that the distribution companies are not going make enough investments to improve their system reliability, and it seems that they will not reach the required system reliability in time, *Energy Authority* is obligated to interfere with the distribution company's decision-making. (Energy Authority 2013)

5.2.1 Maximum outage duration requirement

The maximum outage duration requirement is first mentioned in the *Electricity Market Act* (2013). The requirements main idea is to minimize outage durations in the long run in the Finnish distribution network. According to the *Electricity Market act*, outages', maximum duration is six hours on normal areas, and in unconventional locations, the maximum outage duration is 36 hours. The required maximum outage duration only applies to outages that are caused by storms or a snow load, which are the most common cause for an outage in the Finnish distribution network. The different causes for outages, in 2011, are show in *Figure 11*. It is notable that the year 2011 was a year with an exceptional storm in Finland. Traditionally *wind* or *storm* is causing approximately half of the outages in the Finnish distribution network. (Heikkilä, 2013)

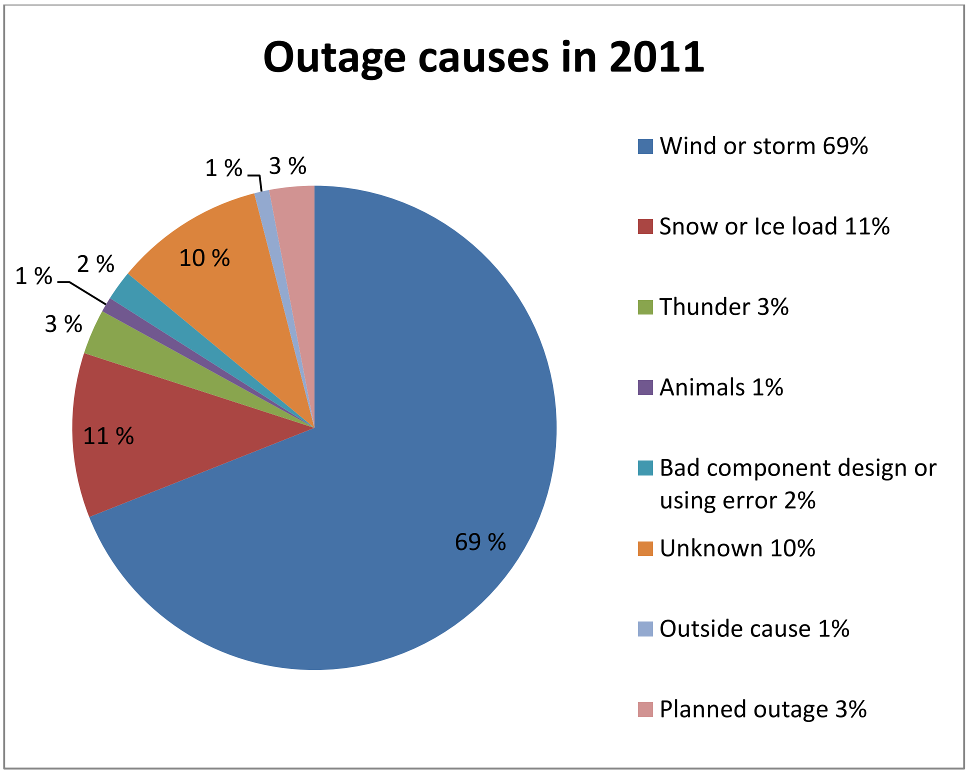

Figure 11: Outage causes in 2011 reported by distribution companies (Heikkilä 2013)

Electricity users connected to the distribution network on difficultly accessible islands are exceptions to the requirement. Same exception can be applied to customers that consume less than 2500 kWh of energy during the last three calendar years or if the customer is located in such a remote area, that it would cause exceptionally large investments to satisfy the reliability requirement.

The maximum outage duration requirement will be applied in stages. The first stage requires that 50 % of the customers (not including leisure houses) must fit the outage requirement. In the year 2023, 75 % of the customers must fulfill the requirement and in the beginning of

2028, every customer must fulfill the maximum outage duration requirement, excluding the exceptions mentioned before. (Heikkilä, 2013)

The same *Electricity Market Act* will influence the amount of compensation electricity distribution companies are obligated to pay to customers due to outages. Before 2016, the maximum compensation was 700 Euros per customer, but after 2016, the maximum amount will be 1500 Euros per customer and after the year 2017, the maximum compensation will increase to 2000 Euros per customer. The new legislation changed the formula on how the outage compensation is calculated. The new compensation is a portion of the yearly electricity transmission payment a customer has paid during a calendar year. The compensation is calculated, in relation to the yearly electricity transmission payment, as follows:

1. 10 %, when the outage duration has been more than 12 hours, but less than 24 hours;
2. 25 %, when the outage duration has been more than 24 hours, but less than 72 hours;
3. 50 %, when the outage duration has been more than 72 hours, but less than 120 hours;
4. 100 %, when the outage duration has been more than 120 hours, but less than 192 hours;
5. 150 %, when the outage duration has been more than 192 hours, but less than 288 hours;
6. 200 %, when the outage duration has been more than 288 hours. (Heikkilä, 2013)

The compensation due to an outage is calculated as listed above, but it cannot increase above the upper limit of 1500 Euros (2000 Euros after 1.1.2018) per customer. One customer receives compensation for every outage according to the list above, but the yearly sum of the compensations per customer cannot be over the upper limit. If the distribution company is not able to provide the required system reliability after 2028, the Finnish Energy Authority can impose a penalty to the company, which failed to improve their system reliability to the required level. The Energy Authority will determine the size of the penalty, but the maximum penalty payment is 10 % of the distribution company's annual turnover. (Energy Authority 2013)

The new Electricity Market Act sets ambitious targets on power system reliability. Most of the Finnish distribution companies face large-scale investments in order to improve reliability of their distribution system. As an example case, the Finnish distribution company *Elenia Oy* faces thousands of outages every year. *Figure 12,* which is data collected from *Energy Authority*'s website, shows the annual number of outages (over 12 hours), *Elenia Oy* has had during the past six years (2010-2015). *The Energy Authority* tracks the number of outage compensations Finnish distribution companies have paid to their customers during the calendar year. *Elenia Oy* is the second largest distribution company in Finland with over 400 000 customers. (Energy Authority 2016a)

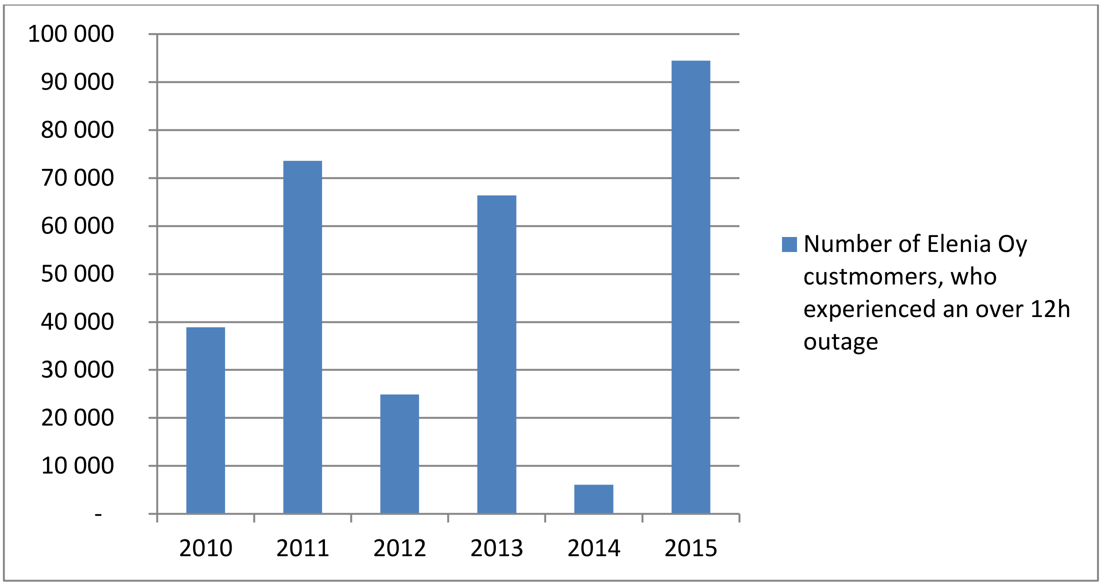

Figure 12: Number of customers, who received outage compensation due to an outage (over 12h hours). Data collected from Energy Authority's website. (Energy Authority 2016a)

As we can see from *Figure 15*, much has to be done in order to achieve the targets set by the *Energy Market Act*. It should also take into account that the outages displayed in *Figure 15* are for 12-hour outages. The target set by the Energy Market Act requires that there are no over six hour outages, excluding unconventional areas.

Utilities can improve distribution system reliability either through preventive actions or by remedial actions. Preventive measures include tree trimming, construction design modification, animal guards, and so on. Preventive measures include also replacing overhead lines with underground cables. The process of replacing overhead lines to underground cables requires extensive initial investments. For example, *Elenia Oy* alone owns 24 000 km of MV cables (Energy Authority 2016a). Remedial actions include adding protective devices, fault location devices and other sensors, and various distribution automation functions. This technology does not usually prevent the fault from happening, but it can reduce drastically the outage duration and the number of customers affected by the fault. (Soudi & Tomsovic 1998)

It is clear that both preventive and remedial actions are necessary for distribution companies in order to achieve the targets set by the Energy Market Act. The smart grid technologies used to improve system reliability within the MV network will be discussed in *Chapter 6* in more detail.

5.3 Relevant changes to the regulation model

The regulation model is a complex legislative framework published by the *Energy Authority*, which defines how much money the distribution company can collect from the customers and how much profit they can gain. The model can be downloaded for free, from the Energy Authority's website (Finnish version). (Energy Authority 2016b)

In a simplified explanation, the regulation model defines the value of the network through network components. This defined network value and the acceptable return of investment rate defines on how much money can be collected from the customers. The different values of network components are listed in the regulation model. If a network component is not listed, the value cannot be added to the network value. In the new regulation model, which came into effect in the year 2016, three new relevant 'feeder automation' devices were added to the list of network components:

- Remote control device for a MV/LV secondary substation or a MV disconnector station.
- Fault indication device for a MV/LV secondary substation or a MV disconnector station.
- Communication device for a MV/LV secondary substation or a MV disconnector station. (Energy Authority 2016b)

These three additions are most likely going to have an effect on the implementation of feeder automation devices to the grid. Prior to the year 2016, distribution companies had to justify the investment on these devices solely on the savings they generated. Since the beginning of 2016, the added value to the network value can have an effect on the investment decisions. Whether this has an effect, depends on the priorities of the distribution company. Some distribution companies' biggest priority might be to keep the prices low, while other companies' biggest priority might be to have the most advanced and most reliable network possible. My personal view is that the company's ownership structure might have an effect on what strategy the company favors. If the distribution company is owned by a town, hence the taxpayers, the low prices for customers might be the number one priority. In these situations, the profits generated through a higher network value, is paid by the customers, hence the 'owners'. If investors and pension funds own the distribution company, the owners do not suffer from increased prices, when network value increases through investments. It is difficult to state that the company's ownership structure might have an effect on the investment strategies, due to the vast number variables to consider in the decision making process.

In addition to the new feeder automation devices, that can be added to the network value, there are incentives. These incentives are taken into account when adjusting the company's profits. The function of these incentives is to encourage the companies to operate, maintain and improve their network more efficiently. All the different types can be found in the regulation model. The most relevant changes made to the incentives for the new regulation model was the *quality of supply* incentive (*Toimitusvarmuuskannustin*), which was a completely new incentive type. This incentive encourages the distribution companies to improve their system reliability by making premature network component investments. Premature investments mean that a component is replaced before the usual component life time expires. (Energy Authority 2016b)

The second major change made, regarding to the incentives, was the doubling of the *quality* incentive (*Laatukannustin*). This incentive encourages the distribution company to decrease outage times. The incentive is calculated by the difference of the outage time between the reporting year and the year before that. If the outage time has decreased, the time is multiplied by the average cost of an outage. This will lead to the quantity of the incentive. The average cost of an outage is discussed more in *Chapter 6.3*. Prior to the year 2016, the incentive was 50 % of the incentive distribution companies get under the new regulation. (Energy Authority 2016b)

5.4 European Union's effect on Finland's smart grid development

5.4.1 Smart grid mandate

In March 2011, the European Commission and EFTA (European Free Trade Association) issued the Smart Grid Mandate M/490, which was accepted by the three ESOs (European Standards Organization), CEN (European Committee for Standardization), CENELEC (European Committee for Electrotechnical Standardization) and ETSI (European Telecommunications Standards Institute) in June 2011. M/490 requests CEN, CENELEC and ETSI to develop a framework for developing standards in the smart grid field. (European Commission 2011)

In order to answer the mandate M/490's request, ESOs established the SG-CG (CEN-CENELEC-ETSI Smart Grid Coordination Group) in July 2011. In 2012, the SG-CG produced the following reports: *Sustainable Processes, First Set of Consistent Standards*, *Reference Architecture* and *Information security and data privacy*. Same year, SG-CG produced a *Framework Document* (CENELEC, 2012), which provides an overview of the reports. It describes how the different elements mentioned above fit together as to provide the consistent framework for smart grids, as requested by M/490. (CENELEC 2016)

5.4.2 Smart meter mandate

The EU Directives concerning common rules for the internal market for electricity and gas (2009/72/EC) and 2009/73/EC) and the EU Directive on energy efficiency (2012/27/EU) require member states to ensure the implementation of intelligent metering systems that shall assist the active participation of consumers in the energy market. This requires that all the EU member states have to have a smart meter in at least in 80 % of the households by 2020.

In order to achieve this goal, the European Commission and EFTA set the mandate M/411 in 2009, which requires CEN, CENELEC and ETSI to develop an open architecture for utility meters involving communication protocols interoperability (smart metering). CEN, CENELEC and ETSI founded the SM-CG (Smart Meters Coordination Group) to achieve the goals in the mandate. SM-CG published a technical report called *functional reference architecture for communications in smart metering systems,* where they identify the functional entities and interfaces that the communications standards in should address (SM-CG 2011). Between the years 2013 and 2014 SM-CG published three reports about privacy and security regarding smart meters. All the reports can be found on CENELEC's website. (CENELEC 2016)

5.4.3 European Electricity Grid Initiative (EEGI)

EEGI (The European Electricity Grid Initiative) proposes a 9-year European RD&D (research, development and demonstration) program initiated by electricity transmission and distribution network operators to accelerate innovation and the development of a smarter electricity networks in Europe. The proposed RD&D program focuses on system innovation rather than on technology innovation. The main focus in the RD&D program is the integration of new technologies under real life working conditions. (ENTSO-E & EDSO 2010)

The first EEGI roadmap and implementation was prepared by ENTSO-E (European Network of Transmission System Operators) and EDSO (European Distribution System Operators) in 2010. An upgraded version of the EEGI implementation plan was produced in 2013 within the GRID+ project. GRID+ is a Coordination and Support Action which has been created by the EU to provide operational support for the development of the EEGI. EEGI is one of the European Industrial Initiatives under the SET-PLAN (Strategic Energy Technologies Plan). The strategic objectives of the EEGI are:

- To transmit and distribute up to 35% of electricity from dispersed and concentrated renewable sources by 2020 and a completely decarbonized electricity production by 2050.
- To integrate national networks into a market-based, truly Pan-European network, to guarantee a high quality of electricity supply to all customers.
- To anticipate new developments such as the electrification of transport.

To substantially reduce capital and operational expenditure for the operation of the networks while fulfilling the objectives of a high quality, low-carbon, Pan-European, market based electricity system. (GRID+ 2016)

6 Improving system reliability with feeder automation RTUs

6.1 Background

System reliability of the electric power system is crucial to the economy and the well-being of the society. All around the world, especially in Finland, aging infrastructure and increasing intermittent generation are challenging system reliability. On top of these challenges, policy makers are demanding increasingly higher system reliability standards from the power system. The *Electricity Market Act* (2013) sets ambitious targets for outage durations in Finland (Energy Authority 2013). System reliability and continuous power supply is not a problem for the distribution network alone, but the problem is definitely one of the biggest for the future distribution networks. Given the fact that nearly 90% of all power outages and disturbances have their roots in the MV network, improving system reliability has to be addressed at this level. This thesis is focusing on faults happening in MV networks. The focus is on the remedial actions, which includes feeder automation technologies. Because outage time reduction is not the only benefits of feeder automation, other benefits are also discussed briefly. (Farhangi 2010)

This chapter will discuss how distribution companies can improve their MV network with feeder automation technologies. The benefits of these technologies come from better fault management, network operation optimization and better asset management. The main function of feeder automation technologies is to indicate the fault and restoring power as fast as possible when a fault occurs somewhere in the MV network.

6.1.1 Underground network and system reliability

One of the most common causes for a fault in the MV network is a fallen tree on an overhead cable. Because of this, the most common way to decrease the number of faults is to replace overhead cables with underground cables. This way, cables are secured form outside disturbances. The underground cabling percentage (underground cable length compared to the total network length) varies a lot between distribution companies. *Helen Sähköverkko Oy* has 99,7 % of their MV cables underground, whereas *PKS Sähkönsiirto Oy* has only 3,9 % of its MV cables underground. Usually distribution companies in cities and other highly populated areas have higher cabling percentages. The total weighted average for underground cabling percentage in Finland's MV network was 18,97 %, in 2015. (Energy Authority 2016a)

Replacing overhead cables to underground cables can be highly expensive. In order to estimate the economic feasibility for placing cables underground, there has to be a clear understanding, how much faults can be avoided in a specific location. This can be difficult to estimate, because fault frequency is highly affected by extreme weather events and storms like *Tapani-myrsky,* in 2011, happen rarely in Finland. VTT and Tampere University of

Technology have published a research report, where the research group estimated an average fault frequency for MV overhead cables and MV underground cables in Finland. According to the research report, overhead cables suffer on average 0,05 faults / km*year and underground cables' fault frequency is between 20–50 % compared to overhead cables, which translates to 0,01–0,025 faults / km*year. The first observation from these values is that, even though 100 % of overhead cables are replaced with underground cables, there is significant amount of faults still happening. (Verho et al. 2009-2011)

It is difficult to estimate how much exactly the underground cabling percentage correlates with distribution companies' outage times. All distribution companies in Finland vary drastically in their topologies and customer densities (how many meters of network cable per customer), but the 11 "city networks", also known as *KV11*, can be compared in relatively fairly matter. According to the data, gathered by *Energy Authority*, the correlation between MV cabling percentage and outage times (SAIDI), caused by an unexpected fault in the MV network, can be analyzed:

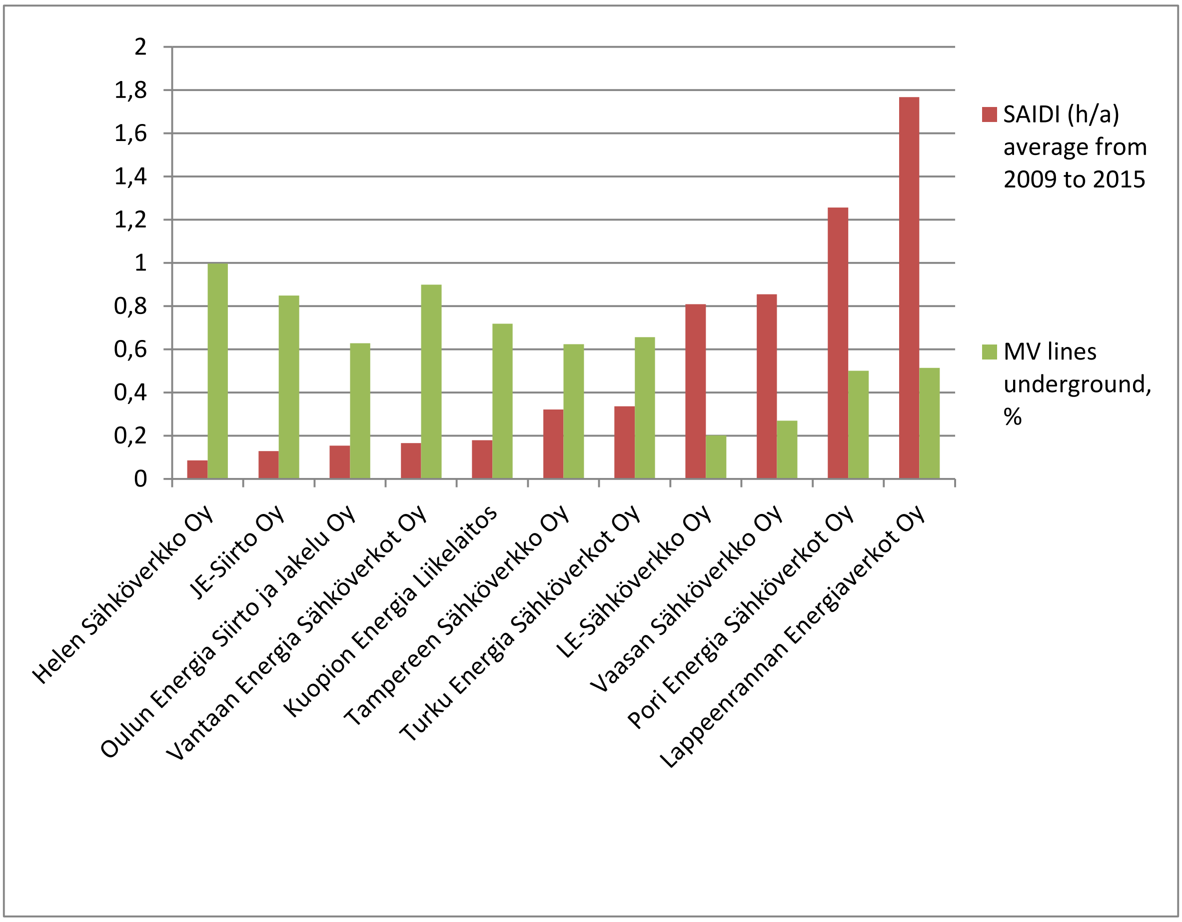

Figure 13: Correlation between SAIDI (unexpected fault in MV network) and MV underground cable - %. Data is collected from Energy Authority's' website (2016a).

As we can see from *Figure 13*, there is a high correlation between SAIDI and the underground cable percentage amongst the 11 distribution companies. The correlation is not perfect, for example, *LE-Sähkverkko Oy* has clearly the least of its MV network cables underground, but three companies have higher SAIDI averages. One explanation for *Lappeenrannan Energiaverkot Oy*'s high SAIDI values are an abnormal outage year in 2013, when the company's SAIDI was 5,8 h/a. According to *Lappeenrannan Energiaverkot Oy*'s report, in 2013 their MV network suffered from extreme weather events and two major sewer leakages causing large outages throughout the distribution network (Lappeenrannan Energia Oy 2014).

6.2 How to quantify system reliability?

There are so many stakeholders (e.g. consumers, DSOs, producers) that it can be somewhat difficult to decide how to measure system reliability in the power system. Distribution companies have been using for a while two performance-based rates for system reliability: SAIDI (System Average Interruption Duration Index and SAIFI (System Average Interruption Frequency Index). The IEEE (The Institute of Electrical and Electronics Engineers) and Distribution Reliability Working Group have developed a standard for both SAIDI and SAIFI. The two organizations have also defined a concept measuring system reliability called MED (Major Event Days). (Larsen et al. 2015)

The IEEE standard 1366 defines SAIDI and SAIFI as follows:

$$SAIDI = \frac{\sum Customer\ interruption\ durration}{Total\ number\ of\ customers\ served} \tag{1}$$

$$SAIFI = \frac{\sum Total\ number\ of\ customers\ interrupted}{Total\ number\ of\ customers\ served} \tag{2}$$

MEDs refer to times (days) during the year when the utility is subjected to significant, yet generally irregular stresses, often due to severe weather. The number of major events experienced by a utility in any given year can vary considerably, yet because they are large events, they have a disproportionate effect on reported reliability. MED factor is used as a supportive term when comparing SAIDI and SAIFI between different utilities. SAIDI and SAIFI cannot provide a fair comparison between system reliabilities of different distribution companies if MED are not considered at all, when comparing system reliability between distribution networks. (Larsen et al. 2015)

IEEE has defined, what counts as a major event. A major event day is a day in which the daily SAIDI exceeds a threshold value, T_{MED}. The threshold value T_{MED} is based on the utility's daily SAIDI values (IEEE 2002). The complete definition can be found in IEEE standard publication: *1366-2012 - IEEE Guide for Electric Power Distribution Reliability Indices*.

In addition to these three measures, Customer Average Interruption Duration Index (CAIDI) is also a common reliability index used by distribution companies. CAIDI tells the average outage duration time for any given customer. In other words, CAIDI is the average restoration time for an outage.

CAIDI is can be calculated as with equation (3) (Larsen et al. 2015):

$$CAIDI = \frac{SAIDI}{SAIFI} \tag{3}$$

CAIDI is a useful measure, when addressing remedial actions to decrease outage times. Because fault frequency cannot easily be affected with smart devices in the MV network, average restoration time for an outage is a useful measurement, when quantifying benefits for a particular feeder automation solution. (Larsen et al. 2015)

6.3 The cost of an outage

In order to make cost-benefit analyses for fault management solutions, a distribution company has to know how much they are losing money during an outage. Without knowing this, they cannot quantify the benefits for a particular investment, presuming that the investment is intended to reduce SAIDI. Estimating the value of undistributed electricity can be difficult. Some could argue that the cost of an outage is equivalent to the amount of electricity the customer would have consumed; hence, the outage cost would be the market value of missed sales. Because electricity is considered as a necessity, the cost of an outage is considered to be significantly higher than just the market value of undelivered electricity. There are different methods to estimate outage costs, but survey based estimations have been considered as the most accurate. The most recent large survey based outage cost estimation for different customer types in Finland was made by Silvast et al. (2005).

The outage costs are dependent on customer type, duration of the outage and the time the outage is happening. Customer Interruption Cost (CIC) is the reference value used to quantify the monetary value of an outage. In Finland, Energy Authority uses the CIC values represented in *Table 3*. The CIC values are categorized by the following customer types: Residential customers, Agricultural customers, Industrial customers, Commercial customers and Public service customers. The weighted average has been calculated based on year's 1995 market statistics. (Energy Authority 2007)

Customer type	Market share	Unexpected permanent outage	
	%	€/kW	€/kWh
Residental	43	0,36	4,29
Agriculture	7	0,45	9,38
Industrial	17	3,52	24,45
Commercial	12	1,89	15,08
Public serice	21	2,65	29,89
Weighted average	100	**1,1**	**11,0**

Table 3: CIC values used by the Energy Authority. (Energy Authority 2007)

The CIC values in *Table 3* only represent unexpected permanent outages. The majority of outages are transient, which last not more than couple of minutes. The cost of short transient faults (couple of seconds) is 0,55 €/kW and for longer transient faults (1-3 minutes) 1,1 €/kW on average. Planned outages have their own CIC values as well, but these faults are not relevant for this thesis. The weighted averages are not directly calculated with the weights and costs of different customer groups. According to Energy Authority (2007), the proposed values take into account the difference between the times outages are happening between customer groups. Energy Authority has proposed the weighted averages as the official CIC values for future studies and applications in Finland. (Energy Authority 2007)

6.4 Benefits of feeder automation

The biggest reasons for automating the MV network is to have better fault management. In addition, there are benefits through network operation optimization and asset management. In reality, feeder automation means more monitoring and controllability at the MV level. Improving monitoring and controllability in the MV requires intelligent RTUs at secondary substations and disconnector stations, which are capable of various different function. The primary functions usually include remote controllability of the switch, fault indication and two-way communication between SCADA or DMS.

Today, primary substations (HV/MV) are usually automated. The monitoring and controllability of the distribution network happens through a protection relay and a circuit breaker at the primary substation. Without any smart devices downstream from the primary substation, a fault somewhere in the distribution network (LV or MV) causes the relay to trip the breaker on the faulted MV feeder, causing an outage to everyone downstream from this MV feeder. The relay is able to send information about the fault type to the control center, but the location of the fault is difficult to estimate. Increasing the monitoring and controllability in the MV network will lead to faster fault location and power restoration. The question for utilities is; which costs more, the smart device or the avoidable expenditure caused by the outages.

6.4.1 Benefits of better fault management with feeder automation

Fault management is the most significant benefit feeder automation brings to the DSOs, at least in Finland. Fault management has two functions: Locating the fault, and power isolation and restoration. The technologies used for these functions are listed in *Table 4*. (Lehtonen & Kupari 1995)

Function	Solution
Locating the fault	Fault indicator, Fault distance computation
Fault isolation and network reconfiguration, self-healing	Remote control switch, Back-up network connections, automated network reconfiguration

Table 4: Benefits of better fault management (Lehtonen & Kupari 1995)

Fault management brings value through reduction in SAIDI. Fault management do not prevent the fault from happening but it is a remedial action to reduce SAIDI. This means that the outage duration decreases and the number of customers affected by the fault decreases. The annual benefits from these technologies can be calculated using this formula (Lehtonen & Kupari 1995):

$$V = E \times C \times r_i \tag{4}$$

Where V is the annual savings on a feeder, E is the average annual energy not delivered due to network faults per feeder, and C is the average CIC value. The CIC value was discussed in *Chapter 6.3* in more detail. The average CIC values of 11 €/kWh and 1,1 €/kW, presented in *Table 3*, are widely used in investment calculations in Finland. The last parameter, r_i, is the per unit outage reduction due to the specific technology/solution. The r_i value can be a value based on experience or it can be calculated on a formula, based on the specific solution (e.g. fault indication). The r_i value for each technology is discussed in more detail in *Chapter 6.4.2* (Lehtonen & Kupari 1995)

The annual average energy not delivered due to a network fault on a feeder, E, can be calculated with the equation (5) (Lehtonen & Kupari 1995):

$$E = \lambda_f \times l \times t_{fm} \times P \tag{5}$$

where λ_f is the average fault frequency of the feeder, l is the length of the feeder, t_{fm} is the average outage duration per fault before the remote automation devices were installed, and P is the power demand on the feeder. (Lehtonen & Kupari 1995)

Fault indication is the first step in fault management. In this context, a fault indicator can communicate remotely with the control center. Without fault indication, DSOs only get information about the fault from the relay, which is at the beginning of the MV feeder, in the primary substation. Fault indicators divide the MV feeder into sections, and when a fault happens, the control center will get the information; in which section of the network has the fault happened. This will allow DSOs to isolate the faulted section and restore power to healthy parts of the grid. The r_i value for fault indication depends on the number of fault indicators on the feeder and the time spent on locating the fault, compared to the whole outage time. (Lehtonen & Kupari 1995)

Fault location computation is the next step in locating the fault. Fault indicators tell DSOs only the section of the feeder where the fault is. The section, especially in rural areas, can be many kilometers long. That is why fault distance computations are crucial part of fault management. Fault location computation need two things to work; an intelligent relay or a RTU in the network gathering data, outage management software at the control center, and communication between these two. In Finland, the most common fault location computation happens with the data gathered by a protection relay at the primary substation and a fault management software (DMS or OMS). An intelligent relay is able to send remotely the power quality data to the control center, where the software calculates an estimation of the fault location. The number of fault indicators and smart monitoring devices (needs to have communication capabilities) at secondary substation level will increase the accuracy of fault location computation. (Sadeh et al. 2013)

The most common fault location computations are based on impedance-based methods. These impedance-based methods estimate the distance of the faulted point from the primary substation based on the impedance estimation as seen from the fault locator point. The impedance based fault location methods usually estimate several locations. This is why the common drawback of the impedance-based methods, is the fact that it cannot determine the exact fault point, only possible fault locations. To overcome this drawback, additional indication devices are needed along the distribution network. (Sadeh et al. 2013)

Fault isolation and power restoration is what happens after fault has been located with enough accuracy. Remote switches can isolate the faulted section of the network and restore power to the healthy parts of the network by reconfiguring the network topology. Network reconfirmation requires back-up connections in the network topology. This network reconfiguration can be done manually by a DSO through SCADA or by an automated intelligence. The intelligence can be centralized or decentralized. When the fault is isolated and the network is reconfigured without DSO's actions, it is usually referred as a self-healing grid. Remote switches or self-healing capabilities do not prevent the fault from happening, but they will decrease the number of customers affected by the fault, thus decreasing the number customers experiencing an outage. The benefits of fault isolation and power restoration can be calculated through the reduction of outages times experienced by the customers. The benefits are directly related to the size of the isolation sections, which is directly related to the number of remote switches along the feeder. (Lehtonen & Kupari 1995)

6.4.2 Estimating SAIDI reduction potentials for different feeder automation technologies

In this chapter, the SAIDI reduction potentials for feeder automation technologies (remote switches, fault indication) are estimated. The parameters of potential SAIDI reduction is the r_i parameter mentioned in in equation (1), in *Chapter 6.4.1*.

As it was stated earlier, r_i value can be based on experience or it can be estimated based on parameters specific for each technology. All equations estimating the r_i value of each technology presented in this chapter take into account the overlapping of the benefits of other r_i values. For example, if fault indication manages to reduce enough outage time, the SAIDI reduction potential for fault location computation becomes smaller. (Lehtonen & Kupari 1995)

For fault isolation and power restoration, the potential SAIDI reduction, r_{sw}, can be estimated based on the number of remote controlled switches, with equation (6) (Lehtonen & Kupari 1995):

$$r_{sw} = \frac{n_{sw}}{n_{sw}+1} \tag{6}$$

The value r_{sw} is the SAIDI reduction potential percentage per one feeder. The n_{sw} value is the number of remote switches on the specific feeder. The key observation related to this formula is the asymptotic nature of the function, which means that the derivate of the function gets closer to zero, when n_{sw} gets bigger. This means that the marginal benefits get smaller when more remote switches are installed on the feeder, which also means that the first installed remote control switch brings the biggest benefits on a specific feeder. (Lehtonen & Kupari 1995)

For fault indication, the potential SAIDI reduction, r_{fi}, is subject to the number of fault indicators per feeder. The r_{fi} value estimation can be calculated with equation (7) (Lehtonen & Kupari 1995):

$$r_{fi} = 0{,}5 \times (1 - r_{sw}) \times \frac{n_{fi}}{n_{fi}+1} \tag{7}$$

The n_{fi}value is the number of fault indicators on the specific feeder. The nature of the function is same as in equation (7), except the benefits are smaller. The equation assumes that fault location takes up 50 % of the total outage time. (Lehtonen & Kupari 1995)

6.4.3 Benefits of Volt/Var optimization and power quality monitoring

Volt/var control is used to increase distribution network's efficiency. The system efficiency improvements lead to energy savings and postponed grid reinforcements. In practice, volt/var control means that the voltage levels and reactive power are managed with capacitors banks and other voltage regulating devices. The benefits of controlling the reactive power and voltage levels are usually discussed in the same context, because capacitors are able to control reactive power, which affects the voltage profile of the line (Lehtonen & Kupari 1995). Volt/Var optimizing relates to enhanced volt/var control capabilities through smart monitoring of the power quality. Volt/var optimizations improvement areas, impacts and benefits are listed in *Table 5*. (U.S. Department of energy 2012)

Improvement area	Impacts	Benefits for utility
Improved voltage control	Lower peak demand Lower over power consumption	Postponed capacity upgrades Reduction in energy consumption
Improved var control	Lower reactive power peak demand Lower line losses	Postponed capacity upgrades Reduction in energy consumption
Integration of DG	Ability to withstand wider range of load and generation conditions	Less expensive system upgrades

Table 5: Benefits of volt/var optimization (U.S. Department of energy 2012)

As we can see from *Table 5*, volt/var optimization has an impact on DG integration to the grid. DG generation usually alters the load profile of the feeder, which means that the maximum power demand of the feeder might increase, when new DG is installed. In addition, DG can have a significant effect on the voltage levels on the feeder. Whether these two problems, caused by DG, are a serious concern for Finnish DSOs, will be discussed more in *Chapter 7*. The benefits of volt/var optimization for DSOs come from postponed capacity upgrades and reduction in energy consumption. (U.S. Department of energy 2012)

In the future, when DG is expected to increase, accurate monitoring of power quality will become more important. Feeder automation RTUs enables larger scale of integration of MV and LV intermittent DG by managing the network in real time with power and voltage monitoring. (Schneider Electric 2015)

6.4.4 Benefits through better asset management

Power quality monitoring at secondary substation level brings useful information about the network components. Receiving real time power quality data from the secondary substations can help detect component problems before they escalate and when it's still easy to address them. This minimizes the probability of costly interruptions during inconvenient time periods. Real time monitoring of e.g. power quality and temperature can also decrease the number of maintenance visits to the substations. Real time monitoring of secondary substations brings monetary savings through postponed power line reinforcements, postponed transformer station reinforcements, avoided inconvenient interruptions and reduced on-site maintenance. (Lehtonen & Kupari 1995)

6.4.5 Added network value from feeder automation RTUs

The network value, which is defined by the regulation model, determines how much revenue the distribution company can generate. The network value and the regulation model was discussed in more detail in *Chapter 5.3*. As it was stated earlier, the new regulation model (2016 – 2023) introduced feeder automation components to the 'list of accepted components'. If a RTU is capable of fault indication, remote control of the switches and two-way communication, the distribution company can add 9100€ to the network value per one installed RTU. In addition to this, one a remote controlled secondary substations or disconnector station will add 550€ to the network value through the value of DMS system and 2200€ through SCADA system. (Energy Authority 2016b)

6.5 Potential savings through CAIDI reduction on a specific MV feeder

The potential savings on a MV feeder for a specific feeder automation technology can be determined if the potential CAIDI (average outage duration) reduction can be estimated. Calculations based on CAIDI reductions are useful when distribution companies are addressing the benefits of fault indication, for example. This is because fault indication in itself does not affect the number of customers affected by a network fault; it only affects fault location time.

The potential savings for one feeder, covering the entire lifetime of the components, can be estimated using equation (8):

$$\sum_{i=0}^{n} \frac{P_{ave} \times CIC \times t_{ind} \times f_f}{60 \times (1+r)^n} \tag{8}$$

Equation (8) is based on equations used in M. Kauppi's thesis (2014).

If the fault frequency f_f of the feeder is unknown, an approximation can be calculated based on the underground cabling percentage, using equation (9):

$$f_f = 0{,}05(1-a)l + 0{,}0175al \qquad (9)$$

Equation (9) is based on prior research made by Verho et al. (2009-2011)

Input data needed for the calculations:

- P_{ave}, average power demand on the feeder, kW
- t_{ind}, reduction in average outage duration, min (CAIDI reduction)
- r, interest rate, %
- f_f, fault frequency, faults/year (optional)
- l, line length, m (if fault frequency is not known)
- a, underground cabling percentage of the feeder, % (if fault frequency is not known)

Input parameters needed calculations:

- CIC, customer interruption cost, €/kWh
- n, the average life time of the components, years
- f_{f1}, average fault frequency on an underground feeder, faults per year (if fault frequency is not known)
- f_{f2}, average fault frequency on an overhead feeder, faults per year (if fault frequency is not known)

The input data needed to for assessing the benefits of CAIDI reduction are all easily accessible. The only value causing uncertainty is the reduction in average outage duration.

Input parameters are all based on previous research conducted in Finland. CIC values are the average customer interruption costs mentioned in *Table 3*: 1,1 €/kW; 11 €/kWh. The value was explained in more detail in *Chapter 6.3*. The average life time of network components n is taken from the Energy Authority's regulation model. The regulation model was briefly discussed in *Chapter 5.3*. The regulation model mentions the life time of a fault indicator as 15 – 25 years (Energy Authority 2016b). In sake of clarity, the average component life time for fault indicators is 20 years. Therefore n is 19 years in equation (8), when the counting starts at year 0. The average fault frequency on underground feeders and overhead feeders are explained in *Chapter 6.1.1*. For overhead feeders, the average fault frequency f_{f1} in Finland is 0,05 faults/km*year and for underground the f_{f2} value is between 0,01 – 0,025 faults/km*year. For clarity, the average fault frequency rate for underground feeders is 0,0175 faults/km*year.

6.6 Optimizing feeder automation in MV networks

Automating the MV network is both a technical and economic optimization issue. This thesis focuses more on the economic side of this issue. From economic point of view, the goal in feeder automation is to minimize the long term costs related to network operations. Even though feeder automation brings value through network operation optimization and asset management, the most significant benefits comes from fault management. Because there are a large number of line switches and tie points in the MV network, automating every single point is not usually cost-effective. The key is to find the most cost-efficient level of automation in the MV network. In general, it is not feasible to get rid of all outages.

As it is for all decisions related to improvements in system efficiency, the optimal level of investments in new technologies can be calculated by minimizing the total lifetime costs including costs related to system inefficiency (outages in this case), investment costs and operational costs. In *Figure 14*, the optimal level of outages is represented, where *Consumer Costs* represent the outage costs and *Distribution Network Operator Costs* represent the total costs related to feeder automation technologies. (Gauci 2013)

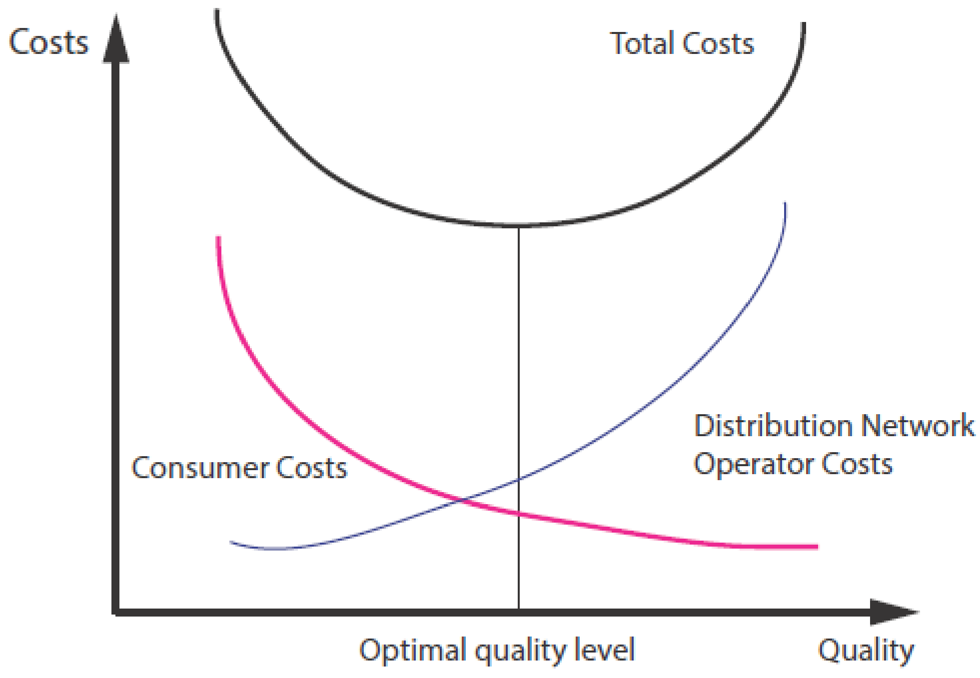

Figure 14: Optimal quality level for distribution companies (Gauci 2013)

The savings in feeder automation, in terms of reducing SAIDI, comes from automatic fault isolation and power restoration. This can be achieved by installing intelligent RTUs into secondary substations along the MV feeder. These RTUs have to have at least the following automation functions:

- Motor drive for the load break switches.
- Fault passage indication

- Two-way communication capabilities with SCADA

RTUs, that are capable of functions mentioned above, are able to divide the network into sections. When a fault happens along the MV feeder, the RTUs can isolate the faulted section and after this, a normally open back-up connection point can be closed, in order to restore power to healthy sections of the feeder. The more RTUs are installed to secondary substations, the smaller the sections are along the feeder. The SAIDI reduction is related to the size of the section and the number of back-up connections. (Koozehkanani et al. 2015)

The most cost-effective strategy for applying intelligent RTUs to the MV network can be modeled and solved with an optimization problem. The objective function for the optimization problem is minimizing the total costs for a predetermined time period. The time period can be the average life time of an intelligent RTU, for example. Decision variables for the optimization problem are the number of RTUs and their placement in the network topology. There are various algorithms for this optimization problem, but one general objective function is as follows (Koozehkanani et al. 2015):

$$Min\ CF = \sum_{t=1}^{n}(OC \times D_t) + \sum_{i=1}^{m}(S_i) \times AC + \sum_{t=i}^{n} MC \times D_t \tag{10}$$

In which CF is the total costs function, OC is the costs related to outages, n is the number of years taken into account, S_i is the decision variable related to the installation of a RTU on the i^{th} switch, m is the number switches that can be equipped with a RTU, AC is the costs related to instalment of a RTU, MC is the annual operational and maintenance costs related to the automation equipment, and D_t is the discount factor for the t^{th} year. More detailed description of the optimization problem is presented in Koozehkanani et al.'s research paper (2015).

6.7 Example of a feeder automation RTU

There are RTUs available and in use in Finland, which are capable of controlling and monitoring remotely secondary substations. Siemens, ABB, Netcontrol and Schneider Electric all offer their own feeder automation RTUs with minor differences, but this thesis will take a look at Schneider Electric's feeder automation RTU. Schneider Electric's T-300 is a modular RTU, which can be placed in various parts of the distribution network. Because RTUs with remote monitoring and control capabilities requires significant investments, the construction of new secondary substations is the most likely place for a T-300 RTUs. An example of a T-300, with specific modules, is represented in *Figure 15*. These different modules represented in the picture below, are all connected to the same unit framework inside the MV/LV substation kiosk, except the monitoring of the LV feeders.

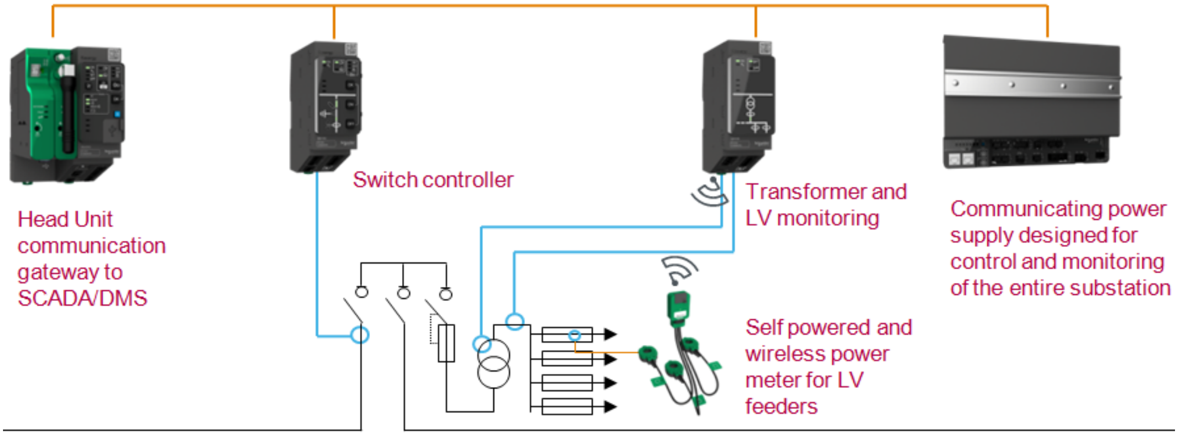

Figure 15: Illustration of a T300 in a secondary substation.

The switch controller module enables the remote control of the load break switch through SCADA or DMS. It also has a fault passage detector for fault indication. Transformer and LV monitoring module is able to measure current, voltage and power flow of the LV side. Head Unit module acts as a two-way communication gateway between SCADA and other modules connected to the main unit framework. The communication between the Head Unit and SCADA complies with security standard *IEC 62351-5*. Power Supply module powers all the other modules connected to the same unit framework. There are also self-powered and wireless power meters for LV feeders, which communicates with the transformer and LV monitoring module through Wi-Fi.

7 Interviews: DSO's current feeder automation level and view of the smart grid

7.1 Background

Six different distribution companies were interviewed in this thesis, in the purpose of getting information about major DSOs' feeder automation level and their opinion regarding their view on the future of smart grid technologies in their distribution network. The answers do not necessary represent the official opinion of the distribution company. Answers only represent the opinion of the company employees that were interviewed. The following distribution companies were interviewed:

- Caruna Oy & Caruna Espoo Oy
- Elenia Oy
- Helen Sähköverkko Oy
- Järvi-Suomen Energia Oy
- Tampereen Sähköverkko Oy
- Turku Energia Sähkverkot Oy

All except *Tampereen Sähköverkko Oy* were interviewed face-to-face at the company's headquarters. *Tampereen Sähköverkko Oy* was interviewed via e-mail. *Caruna Espoo Oy* and *Caruna Oy* was interviewed in the same context for convenience reasons. The interview answers are not separated for these two companies. All the face-to-face interviews were conducted between 16.9.2016 – 2.10.2016.

The questions were divided into two different categories. The first category focused on the general technical information about the network and the current feeder automation RTUs in their network. This category was interviewed and documented with a predetermined form, where the questions were as simple as possible. The questions were design to be simple in order to get as comparable results as possible. The second part of the interview consisted of three open questions related to smart grid views in general.

Technical questions that were asked from the DSOs were design to show more detailed technical information about the network components in the MV network, in contrast to the public information available at Energy Authority's website. These questions were asked to get a sense of magnitude of possible places feeder automation technologies can be installed. These questions were also meant to get an idea, what is the current automation level at the medium voltage level. The most important technical questions asked in the interview:

- HV/MV substation automation level (%)
- Number of Pole Transformer stations - Number of new ones per year?
- Number of Kiosk Transformer stations - Number of new ones per year?
- Number of MW pole switches – Number of new ones per year?

- Current automation level at kiosk transformer stations (remote control)?
- How many new kiosk transformer stations are going to be automated? (Plan)

Open questions were designed to get opinions and views about the external drivers affecting future smart grid trends in Finland. Three questions were asked from each distribution company. First question was: "*What legislations / regulations should be renewed in order effectively support the implementation of smart grid technologies?*". With this question, the goal was to discover negative aspects about the regulation model (discussed in *Chapter 5.3*) or other legislative things that should be changed in order to ensure a faster implementation of smart grid technologies. This question was not targeted to the MV network alone. The second question, "*What challenges do you expect smart grid solutions to solve in the near future for distribution companies (5 to 10 years)?* ", was directed to smart grid technologies in distribution network alone. This question was design to get information about DSOs needs regarding what challenges they would like to be solved with smart grid technologies in the near future. Because new technologies tend to be developed to solve customers' problems, the answers to this question will likely give a hint what smart grid technologies might be available in the near future for DSOs. The third question, "*Views on the effects of the increasing solar power production?*", is a straight forward question related to the increase in renewable DG, specified in solar power, and its effect on the grid. Wind power is ruled out, because, according to research made by Gaia Consulting Oy (2014), small scale wind power production as DG is not going to significantly increase in Finland.

7.2 Answers and discussion

Technical question: According to the interviews, it seems that the automation level of primary substations is 100 % in Finland. Every distribution company interviewed informed that all of their primary substations were automated. This answer was somewhat expected. It is notable to mention that there are different stages of automation. But in this context, 100 % referred to remote controllability switches and breakers. The answers to the questions directed to the number of existing and new switching stations, pole transformer stations and kiosk transformer stations can be found in the *Appendix*. The automation level of kiosk transformer stations is presented in *Figure 16*. *Caruna Oy* did not deliver information related to the automation level. The automation level of kiosk transformer stations was chosen for the interview, because investments are focusing currently more on new underground substations kiosks, rather than new pole transformer stations.

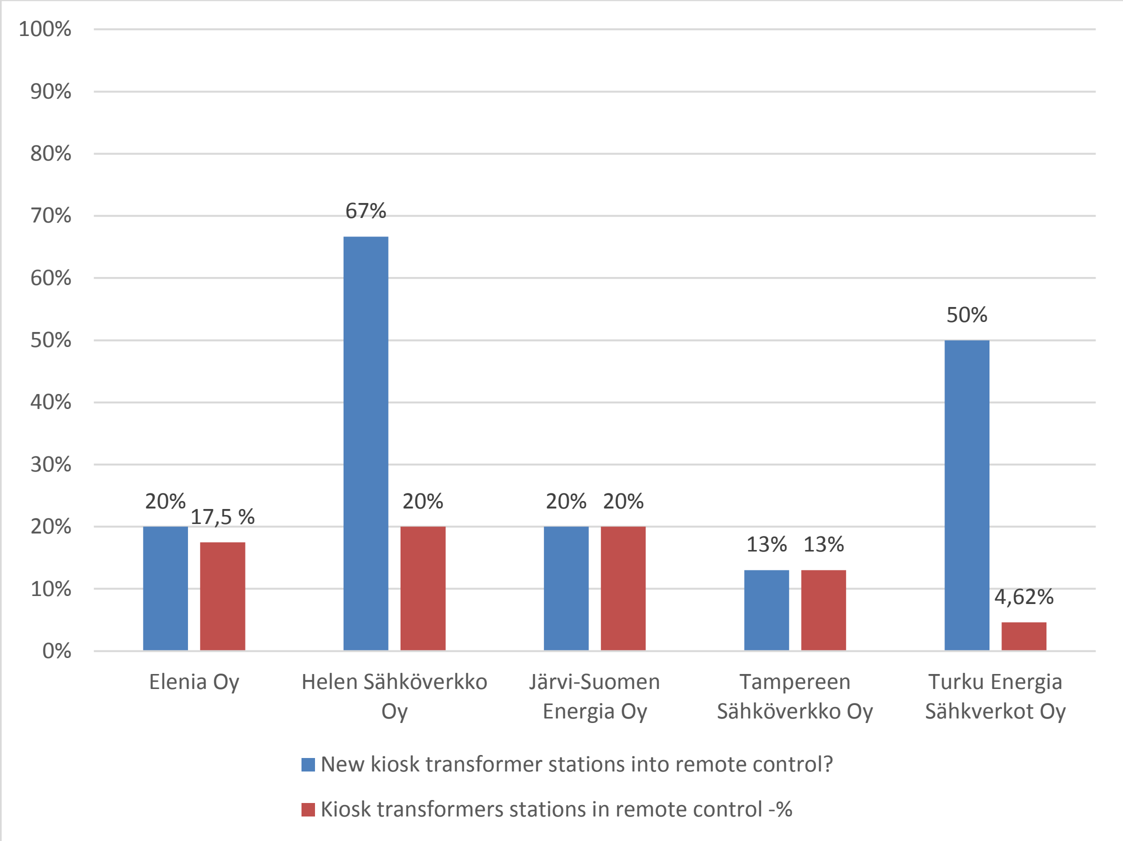

Figure 16: Kiosk transformer station in remote control (existing and new) by different DSOs

Figure 16 shows that *Elenia Oy, Helen Sähköverkko Oy* and *Järvi-Suomen Energia Oy* have almost the same automation level in their kiosk transformer stations. *Helen Sähköverkko Oy* is the only company out of the three, which is going increase the share of remote controllable kiosk transformer stations in the near future. *Tampere Sähköverkko Oy* has 13 % of kiosk transformer stations automated, and it seems that their near-future plan is not to increase this. *Turku Energia Sähköverkot Oy* has the lowest current automation level in kiosk transformer stations, but as we can see from *Figure 16*, half of their new kiosk transformer stations are going to be remote controllable. This means that *Turku Energia Sähköverkot Oy* is expected to see an increase in their automaton level (remote control) in the near future. It is worth mentioning that *Järvi-Suomen Energia Oy* and *Elenia Oy* are rural network. This means that their network topology differs from the city-networks, and their outage times are significantly higher due to the long radial overhead feeders. The values for new "new kiosk transformer stations into remote control" is only an estimate. The interviewees emphasized that it varies year by year. For example, *Elenia Oy* had a period between 2009-2016, where the company invested heavily on remote control transformer stations.

Open questions:

"*What legislations / regulations should be renewed in order effectively support the implementation of smart grid technologies?*":

The most common critique towards the current legislation / regulations related to the regulation model's component value list. *Helen Sähköverkko Oy* and *Elenia Oy* mentioned that the 8-year regulation period might be too long regarding adding new components to the component value list. It would be beneficial, that emerging technologies could be added to the list during this 8-year period. *Elenia Oy* emphasized that this applies only for mass installations, and that the current incentive for new innovations works well with testing new technologies. *Tampere Sähköverkko Oy* mentioned that every component should be able to add network value, and not just the components on the 'list'. Two companies mentioned regulation model's incentives. *Turku Energia Sähköverkot Oy* mentioned that the incentive scheme should be more clear and direct, compared to the current, more indirect-based, incentive scheme. *Caruna Oy*'s opinion differed from the others' opinions. Regarding electricity storage, *Caruna Oy* wanted to open a dialogue about the possibility of the DSO ownership of storages (at the moment, DSOs cannot own electricity storage). Therefore, these electricity storage components could be added to regulation model's 'component value list'. Overall, the answers related to regulation and legislation were directed to the regulation models 'component value list'.

Majority of the interviewees emphasized the importance of the 'component value list'. If certain automation component is not in this list, distribution companies may hesitate to invest in this technology, because they cannot add the components value to the network value. As it was described in *Chapter 5.3*, the network value determines how much turnover the company can make.

What challenges do you expect smart grid solutions to solve in the near future for distribution companies (5 to 10 years)? "

The most common answer in this question, was fault detection/location. Three out of six companies brought up fault detection/location as one of the biggest challenges for future smart grid solutions to be solved. Fault location is especially essential in long radial feeders, where gird sections can be many kilometers long. *Caruna Oy* was the only company to bring up demand response (*Caruna Oy* used the term demand side management). According to Caruna Oy: "Demand side management is in the key role in cost-efficient solution for power balance issues. DSOs must have active role to support the TSO as almost all new demand side management-resources are in DSO grid." *Helen Sähköverkko Oy* was the only company to mention that AMI measurements could be more accurate in the future. More accurate smart meter measurements are in line with the EU's vision to have 15-minute measurement interval in AMI. This was discussed in more detail in *Chapter 4.6*. *Elenia Oy* mentioned a future where the grid is self-monitored, more self-healing, and a future where secondary substation kiosks have automation as priority number one, and not human interaction.

Views on the effects of the increasing solar power production?

Distribution companies did not seem to be that concern about the increase in solar power production, within the distribution network. *Helen Sähköverkko Oy* was the only company to mention that there could be some issues on the grid, when PV-production increases. According to the company, the demand for power and voltage control is going increase when PV-production increases. This problem was mentioned in *Chapter 6.4*, when the benefits of feeder automation were discussed. It seems that majority of DSOs are not concerned about the increased volt/var control needed due to the increasing PV-production. *Elenia Oy* mentioned that low voltage automation has to get better, AMI measurements have to become more precise, and demand forecasting has to improve. *Elenia Oy* mentioned that if these improvements do not happen, problems will occur with future PV production.

Caruna Oy had an explanation why PV-production will not cause problems in with DSOs in the near future: "Within 5-10 years there should not be a problem as Finnish grid dimensions are quite generous due to electrical heating and cold winters. During summer, there is plenty of free capacity and during winter added PV-production might ease out peak load situations." According to this statement, it seems that the distributed solar power is not a significant concern for Finnish DSOs, even though the statement does not mention the need of better volt/var control. It is worth mentioning that Finland has relatively low deployment of PV-production, compared to some other European countries, which means that the challenges PV-production brings to the DSOs will be a bigger concern later in the future, considering that the trend in the PV-panel markets stays the same.

8 Case: Optimizing the number of feeder automation RTUs in an underground ring network

8.1 Description the optimization problem

This chapter is aiming to study how Energy Authority's new cost estimations for feeder automation technologies affect the investment feasibility of the technology. The feasibility is studied by modeling investment feasibility in an underground ring network. The sample network topology is based on the average technical data for '*KV11*[2] companies and a predetermined number of secondary substations. The model is done with an optimization problem, with different fault frequencies. The aim of the study is to find the optimum automation level for different fault frequencies and showing how much savings the utility gains with this optimum automation level, comparing it to a situation with no automation.

The optimization problem is finding the optimal number of feeder automation RTUs for an average underground network with 23 secondary substations. The key is to find the most cost-effective self-healing network with different fault frequency values, by placing optimum number of intelligent RTU into secondary substations. The goal is to optimize the automation level from economic point of view, by minimizing the total costs over the predetermined time period. In this case, only the benefits from reduction of SAIDI and costs defined by the Energy Authority's regulation model (2016b) are taken into consideration. This means that the optimal feeder automation level is higher than the solution of this problem, if other benefits are also taken into account. Therefore, this study brings only supportive value to decision making process, relating to investments in feeder automation technologies. The reason for excluding other benefits from this optimization problem, such as better asset management and volt/var optimization, is that they are too difficult to quantify with enough accuracy. All the needed parameters used in this problem, except the 23 secondary substations and the predetermined network topology, are based on average data used or published by the Energy Authority. The optimization is conducted for the next 20 years. This value is based on the component life time expectations for feeder automation RTUs used by the Energy Authority (Energy Authority 2016b).

The network topology is two underground MV feeders, forming a ring network, with 23 secondary substations in total. The two MV feeders are connected at the end, with one normally open load break switch. The network topology is illustrated in *Figure 17*. The assumptions in this case, is that the network topology and positioning of the secondary substations are 100 % homogenous, which means that the distance between the secondary substations are the same, and the power demand is evenly distributed through the two feeders and the secondary substations. The number of substations (23) has been chosen for practical reasons.

[2] Helen Sähköverkko Oy, JE-Siirto Oy, Kuopion Energia Liikelaitos, Lappeenrannan Energiaverkot Oy, LE-Sähköverkko Oy, Oulun Energia Siirto ja Jakelu Oy, Pori Energia Sähköverkot Oy, Tampereen Sähköverkko Oy, Turku Energia Sähköverkot Oy, Vaasan Sähköverkko Oy and Vantaan Energia Sähköverkot Oy

It is also assumed that the RTUs are placed to the secondary substations as efficiently as possible, meaning that the distance between the RTUs are as even as possible.

The RTUs are dividing the network into sections. In this optimization problem, the RTU's are able to indicate the fault to a specific section, isolate the fault by opening the closest load break switches, and restore power to the healthy parts of the feeder after closing the normally open load break switch. This study does not clarify, how this fault isolation and power restoration sequence is conducted. It is assumed that the switching sequence takes less two minutes, which means that customers on the healthy parts of the network will experience only a transient outage. Customers inside the faulted section, will experience a permanent fault, taken into consideration that their outage time is reduced compared to the reference level. The reference level is the average outage restoration time (CAIDI) before any feeder automation was installed.

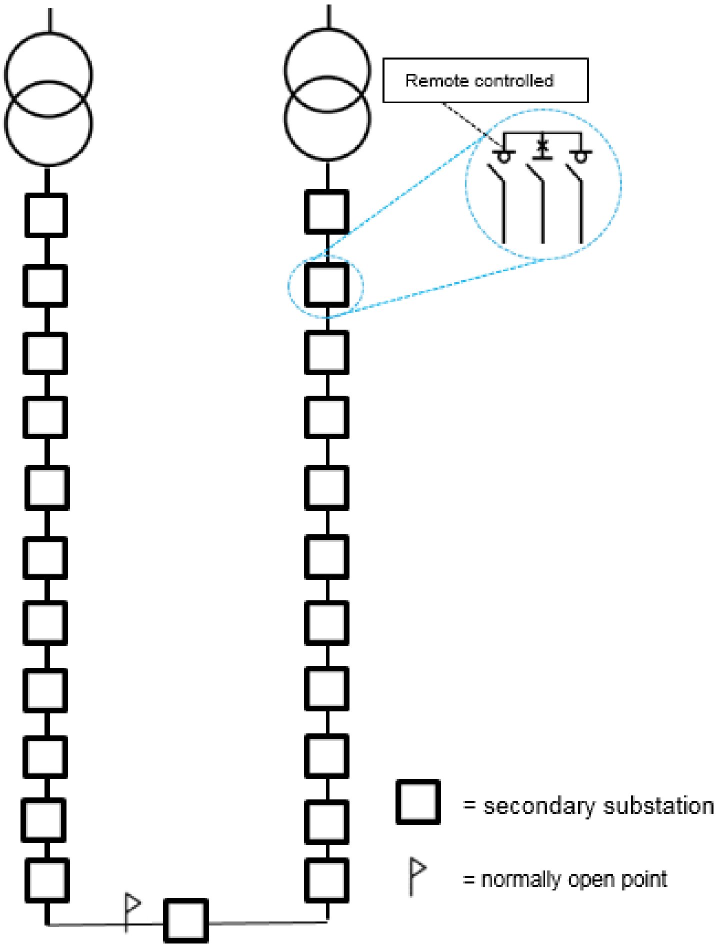

Figure 17: Network topology of 23 secondary substations in a ring network.

8.2 Objective function, decision variables and parameters

The objective is to minimize total costs, CT, over the predetermined time period, where the number of RTUs, X, is the decision variable. The objective function is as follows:

$$Min\ CT = CR \times X + \sum_{i=0}^{n} D_i \times OC_{tot} \tag{11}$$

s.t.

$$X = integer,$$
$$2 \leq X < N,$$

In which CT is the total costs, n is the number of years, CR is the costs related to the RTUs, X is the number of RTUs, OC_{tot} is the cost function related to outage costs, D_i is the discount factor for the i^{th} year, and N is the number of secondary substation, which is 23 in this optimization problem. Decision variable X is 2 at minimum, because 2 RTU's are needed to isolate a faulted section.

The parameters needed for this optimization problems are as follows:

- f, fault frequency (faults/year)
- CR, the total costs related to the instalment of a RTU
- l, length of the network (km)
- P, Average power demand on feeders (kW)
- $\text{CAIDI}_{1,}$ Outage restoration time before automation (h)
- $\text{CIC}_{per,1}$, average cost of interruption, permanent outage, over 3 min outage (€/kWh)
- $CIC_{per,2}$, average customer interruption cost, permanent outage, over 3 min outage (€/kW)
- CIC_{temp}, average customer interruption cost, long transient fault, less than 3 minutes (€/kW)
- r, interest rate

Costs CR are defined by the Energy Authority's regulation model. The total cost estimations related to fault indication, remote controlled switches and communication are determined separately. Energy Authority has considered every cost related to devices related to the three functions mentioned. The total costs include for example the RTU itself, instalment, planning, construction, transportation and configuration of the components (Energy Authority 2016b). These cost estimations do not consider operational costs, such as maintenance costs. In this case, the costs related to the SCADA and DMS software systems are not considered. These costs are ignored, because distribution companies usually already have these software systems implemented, when they are addressing decisions related to feeder automation RTUs. The estimated total costs related to feeder automation RTU are presented in *Table 6*:

	value (€)	lifetime (years)
remote control	3100	20 - 35
fault indication	1200	15 - 25
communication	4800	15 - 30
Sum	9100	20

Table 6: value of feeder automation RTU's by its functions (Energy Authority 2016b)

The number of years used for this optimization problem is 20, which means that $n = 19$. This is based on the average lifetime value for the fault indication function, which is the shortest lasting component.

The technical features of the network are based on the average values for *KV11* distribution companies. All the technical parameters can be calculated from the data obtained from the Energy Authority's website (2016a). The technical parameters used in this optimization problem are as follows:

Length (km) of the ring network can be calculated from the number of secondary substations, assuming that the secondary substations are distributed evenly on the entire medium voltage network for the *KV11* companies. The total amount of secondary substations and total length of the medium voltage network for *KV11* distribution companies can be found in the Energy Authority's report (2016a). The Length of the ring network can be calculated with equation (12):

$$\frac{Number\ of\ secondary\ substaions}{Total\ amount\ of\ secondary\ substaions\ in\ MV\ network} = \frac{Lentgh\ (km)}{Total\ length\ of\ the\ MV\ network} \tag{12}$$

$$Length = \frac{23 \times 12\ 400\ km}{14\ 288} = 20\ km$$

Average power demand (kW) on the two feeders can be determined by three different parameters: The *length (km)* of the predetermined ring network, the total length of the entire *KV11's* MV network, and the total power demand of the entire *KV11's* MV network. The data can be found in the Energy Authority's report (2016a). The average power demand, P, can be calculated with equation (13):

$$\frac{20\ km}{Total\ network\ length\ (km)} = \frac{P}{Total\ power\ demand\ (kW)} \tag{13}$$

$$P = \frac{20km \times 168000\ kW}{12400km} = 2700\ kW$$

Outage restoration time before automation ($CAIDI_1$), is based on the average CAIDI values for all *KV11* companies, from 2010 to 2011. It can be assumed that 5 to 6 years ago, feeder automation level was insignificant. In 2010, the average CAIDI for *KV11* was 0,9 hours. In 2011, the average CAIDI value for *KV11* companies was 1,1 hours (Energy Authority 2016a). Therefore, the $CAIDI_1$ average before automation is 1,0 hours.

Outage restoration time after automation ($CAIDI_2$) is the time it takes to restore power to a faulted section. $CAIDI_2$ is defined by the size of a faulted section, and the reference CAIDI value, which is $CAIDI_1$ in this case. Assuming that fault location takes up 50 % of the total outage restoration time (Lehtonen & Kupari 1995), the outage restoration time after automation is determined with equation (14):

$$CAIDI_2 = (1 - 0{,}5 \times (\tfrac{s-1}{s})) \times CAIDI_1 \tag{14}$$

In which s is the number of sections, the RTUs are forming to the network. **The number of sections, $\boldsymbol{s}$,** is calculated with equation (15):

$$s = X + 1 \tag{15}$$

In which X is the decision variable; the number of RTUs.

The cost function, related to outages, is based on two parts; secondary substations inside the faulted section and secondary substations outside the faulted section. It is assumed that there happens only one fault simultaneously and that the fault happens on a feeder, between substations. This means that faults that happen inside substations are not considered in this problem.

The power is restored to the customers outside the faulted section in less than two minutes, and the customer inside the faulted section experience an outage, which duration is determined by the equation (14).

Cost function for the faulted section, $\boldsymbol{OC_1}$, is determined by equation (16)**:**

$$OC_1 = CAIDI_2 \times \mathrm{CIC}_{per,1} \times P \times f \times \frac{a}{N} + CIC_{per,2} \times P \times f \times \frac{a}{N} \tag{16}$$

In which, $CAIDI_2$ is determined by equation (14), a is the number of substations inside a faulted section, N is the number of secondary substations, f is the fault frequency, P is the average power demand on the feeders, and $\mathrm{CIC}_{per,1}$ and $\mathrm{CIC}_{per,2}$ are the average customer interruption costs for permanent faults. Based on the Energy Authority's report (2007); $\mathrm{CIC}_{per,1} = 11\frac{€}{kWh}, \mathrm{CIC}_{per,2} = 1{,}1\frac{€}{kW}$.

The number of secondary substations inside a faulted section, $\boldsymbol{a}$, is defined by the following with equation (17):

$$a = \frac{N - X}{s} \tag{17}$$

In which N is the number of secondary substations, X is the number of RTUs (decision variable), and s is determined by equation (15). It is assumed that a fault happens between substations, not inside one.

Cost function for the healthy section(s), $\boldsymbol{OC_2}$ is determined by equation (18):

$$OC_2 = \left(1 - \frac{a}{N}\right) \times P \times f \times \mathrm{CIC}_{temp} \tag{18}$$

The **total outage related costs, $\boldsymbol{OC}$**, are calculated is determined by equation (19):

$$OC = OC_1 + OC_2 \tag{19}$$

Cost without automation, CW, is calculated in order to quantify the potential savings the optimum automation level will bring to the distribution company. The annual cost without automation is calculated with equation (20):

$$CW = (CAIDI_1 \times \mathrm{CIC}_{per,1} \times P \times f + CIC_{per,2} \times P \times f) \times 0{,}5 \tag{20}$$

(20) has a multiplier of 0,5, because one fault only disables the other side of the ring network.

Savings, $\boldsymbol{S}$. The savings the optimum level of automation will bring to the distribution company can be calculated with equation (21):

$$S = CW - CF \tag{21}$$

The savings, calculated in equation (21), are only related to the avoided outage costs.

The annual discount factor, $\boldsymbol{D_i}$, is defined by the interest rate, r. In this optimization problem, the value 0,04 is used for, therefore r = 0,04. The annual discount factor is calculated with equation (22):

$$D_i = \frac{1}{(1+r)^i} \tag{22}$$

8.3 Results

The optimization problem was executed in *Excel,* and the solution for the objective function, is solved with *Excel Solver*. The optimization problem is solved for each fault frequency value presented in *Table 7*, where the *Decision variable, n*, column is presents the optimal decision variable; hence, the solution for the problem for the specific fault frequency. The third column, *Objective function, CF*, presents the value for the objective function; hence, the total costs with the optimal automation level. *Cost without automation, CW,* column presents the outage costs related to the specific fault frequency, when no automation has been installed. *Savings, S*, column presents the savings the distribution company gains, if they invest to the optimum number of smart RTUs, compared to the situation with no installed automation at secondary substations.

Fault frequency, f	Decision variable, n	Ojcetive function, CF	Cost without automation, CW	Savings, S
0,2	2	43 630 €	46 176 €	2 546 €
0,3	2	56 345 €	69 263 €	12 918 €
0,4	3	66 905 €	92 351 €	25 446 €
0,5	3	76 806 €	115 439 €	38 633 €
0,6	3	86 708 €	138 527 €	51 819 €
0,7	4	94 913 €	161 615 €	66 701 €
0,8	4	103 272 €	184 702 €	81 430 €
0,9	4	111 632 €	207 790 €	96 159 €
1	5	119 417 €	230 878 €	111 460 €
1,1	5	126 809 €	253 966 €	127 157 €
1,2	5	134 201 €	277 053 €	142 853 €
1,3	5	141 593 €	300 141 €	158 549 €
1,4	6	148 828 €	323 229 €	174 401 €
1,5	6	155 559 €	346 317 €	190 758 €
1,6	6	162 290 €	369 405 €	207 115 €
1,7	6	169 020 €	392 492 €	223 472 €
1,8	6	175 751 €	415 580 €	239 829 €
1,9	7	182 470 €	438 668 €	256 198 €
2	7	188 721 €	461 756 €	273 035 €
2,1	7	194 972 €	484 844 €	289 872 €
2,2	7	201 223 €	507 931 €	306 708 €

Table 7: The optimal number of RTUs with different fault frequencies.

If we examine a situation, where the fault frequency $f = 1\ faults/year$, the most cost efficient automation level is five smart RTUs. These five RTUs should be placed evenly to the secondary substations along the two feeders. This corresponds to automation level of $\frac{5}{23} \approx 22\ \%$. The total cost of operating the two feeders leads to lifetime costs of 119 417 €. Without any automation, the total costs, due to outages, would be 230 878 €. This would lead to savings of 111 460€, in the next 20 years.

8.4 Discussion about the results

This optimization problem took only outage duration reductions into consideration, which means that the results presented in *Table 7* shows the minimum number of RTUs distribution companies should invest into a ring shaped network topology with 23 secondary substations. Because the technical parameters used in this optimization problem are the average technical parameters from the *KV11* distribution companies, this does not apply for rural network, where distances between secondary substations are larger and average power demand is most likely much lower for a same sized network topology. Also, the total outage related costs, OC, can only be used for a self-healing network, where the back-up connections are perfect, which means power can be restored to every healthy sections of the network. In rural network, where feeders are long and radial, back-up connections are not usually available.

If this optimization problem would be used for overhead networks, or networks with a mixture of underground feeders and overhead feeders, the costs related to the network components, CF, should also include components meant for overhead feeders.

If a distribution company is making investment decisions in feeder automation only based on improving fault management, these solutions presented in *Table 7,* only give an approximation about the optimal automation level from economic point of view. In reality, the optimal automation level is somewhat higher, because feeder automation brings value through better asset management and network operation optimization. The additional benefits feeder automation RTUs bring:

- Network operation optimization
    - Postponed network reinforcements through better volt/var optimization
    - Reduction in energy consumption through better volt/var optimization
- Better asset management through increased data received from the field
    - Less visits to the field through real-time monitoring
    - Avoiding costly interruptions during inconvenient time periods through real-time monitoring
- Enables integration of intermittent DG
    - Ability to withstand wider range of load and generation conditions through volt/var optimization
- Preparation for the maximum outage duration requirements
    - *Electricity Market Act*'s maximum 6-hour outage after 2028

The benefits listed above are somewhat difficult to quantify and some of them, for example integration of intermittent DG, are more of a technical requirement, rather than function that generates savings. If these benefits can be quantified, they can easily be added to the optimization problem, in order give more accurate estimations for the optimal feeder automation level for a specific MV feeder. In addition to the list above, better service quality usually affects positively on the company's reputation.

Because the optimization problem is calculated for 20 years, some parameters are bound to change during this time period. Because outage requirements are becoming stricter and compensations distribution companies have to pay are getting higher (discussed in *Chapter 5.2.1*), cost of interruptions, CIC, values can be expected to increase in the future. This increase would mean that feeder automation RTUs would bring more benefits in the near future. In addition, the CIC values currently used by the *Energy Authority*, are somewhat outdated already, because these values were estimated before *Electricity Market Act (2013)* was published. The outage compensations have already risen, and will increase more in 2018 (Energy Authority 2013).

In addition, the distribution company can add 9100€ to the network value per one RTU, that is capable of remote control switching, fault indication and two-way communication with SCADA/DMS. One remote controlled secondary substation or disconnector station will also add 2750€ to the network value through the increased value of the SCADA and DMS systems. Whether this has an effect on the investment decisions is hard to estimate. As it was discussed in *Chapter 5*, the motto and ownership structure of the distribution company may have an effect whether added network value will affect investment decision; companies that emphases low consumer prices may not see added value as important as companies that emphases highest possible service quality as their motto. Ownership structure's possible effect on the distribution company's motto was discussed in *Chapter 5.3* in more detail.

This optimization model, presented in this chapter, offers a groundwork for future studies in feeder automation feasibility. Future studies could model the feasibility of feeder functions in more detailed fashion. In order to improve the optimization model, different fault types and different benefit could be added to the model. Different fault types are important, in order to model a real life situation. In the current model, only faults happening between substations were considered. In the real world, there are also faults happening inside primary and secondary substations. If these fault types would be added to the model, it would require modifications to the model and added fault statistics. At least the function (17), *the number of secondary substations inside a faulted section,* should be defined again. The other improvement that could be done to the model is to include other benefits as well. Because fault management is not the only benefit DSOs get from feeder automation, it would help the decision making process, if other benefits would be considered as well. Other benefits, such as asset management, network operation optimization and renewable integration, should be quantified somehow, in order to include them to the model. Quantifying these benefits would be difficult, because there is a lack of research made in these areas.

9 Conclusion

This thesis studied two different research questions related to smart grid technologies and feasibility of feeder automation in Finland. These two questions were studied by interviewing six different Finnish distribution companies and creating an optimization model for the feasibility of feeder automation.

The interviews studied the opinions of Finnish DSOs related to different questions about smart grid technologies. Interviews also investigated the current automation level of their MV network and future plans regarding this automation level. The more general questions were aimed to get DSOs' views on regulation affecting smart grid deployment and views on what kind of future they see, regarding smart distribution network in Finland. The biggest issue the interviewees had regarding regulation was the fact that the 8-year regulation period might be too long. During this regulation period, no new smart grid technologies can be added to the regulation model's 'component value list'. The interviewees emphasized the importance of 'component value list'. If a new technology is not on this list, distribution companies might hesitate to invest in it. The second biggest takeaway regarding smart grid technologies in the distribution network was the expectations about the future. The biggest expectations the interviewees had towards future smart grid technologies, was related to fault management. Based on the interviews, the increase in distributed intermittent generation was not seen as a significant concern for the grid. One explanation for this was the fact that the Finnish grid dimensions are designed to withstand high power demands during cold winters. One interviewee mentioned a concern regarding the increase of distributed solar PV production.

The case study investigated the feasibility of feeder automation technologies based on Energy Authority's cost estimations. The case study calculated the optimum automation level at secondary substations in underground ring network. In this case, the network topology used was based on a predetermined number of secondary substations, 23, and the average technical network data from Energy Authority's website. The results were calculated for different types of fault frequency values. With the fault frequency of 1 fault/year, the optimum automation level was 5 automated secondary substations out of 23. This corresponds to 22 % level of automation. The optimization problem only considered faults that happen between substations. The optimum automation level is could increase in the future due to the new outage requirements set by the Energy Authority. Stricter outage requirements will generate more expensive compensations for DSOs. This will increase the CIC values, which will directly increase the feasibility of technologies that decrease outage times.

For future studies, faults inside substations should be also considered. This would require minor adjustments to the model and more statistics on how common substation faults are. In addition to this, the optimization model did not consider other benefits rather than outage time reduction. Improvement for future studies could also include other benefits to the model as well, such as asset management, operation optimization and renewable integration. These benefits are significantly more difficult to quantify, compared to benefits through outage reduction. As indirect benefits, the new regulation model, set by the Energy Authority, increases the feasibility of investing to feeder automation technologies. After 2016, distribution companies are able add 9100 €/substation to their overall network value, when the following feeder automation functions requirements are met on the specific substation; remote control, fault indication and communication. In order to estimate how much this affects investment decisions, might depend on the overall strategy of the distribution company. If the distribution company's only strategy is to keep prices low, they might not see it beneficial to increase the value of their network, which increases the accepted annual turnover of the company.

References

Agüero, J. 2012. Applying self-healing schemes to modern power distribution systems. 2012 IEEE Power and Energy Society General Meeting. Report. Available at: http://faratarjome.ir/u/media/shopping_files/store-EN-1428390330-3772.pdf.

Albadi, M.H., El-Saadany E.F. 2008. A summary of demand response in electricity markets. Electric power systems research. Vol 78 (2008) 1989-1996. DOI:10.1016/j.epsr.2008.04.002.

Allan, R. N., M. G. Da Silva. Evaluation of reliability indices and outage costs in distribution systems. IEEE Transactions on Power Systems. Vol 10 (1995) 413-419. DOI: 10.1109/59.373965.

ASAP-SG. 2009. Security profile for advanced metering infrastructure. The Advanced Security Acceleration Project (ASAP-SG). The NIST Cyber Security Coordination Task Group. Report. Available at: http://osgug.ucaiug.org/utilisec/amisec/Shared%20Documents/AMI%20Security%20Profile%20(ASAP-SG)/AMI%20Security%20Profile%20-%20v1_0.pdf.

Bloustein, E. 2005. Assessment of Customer Response to Real Time Pricing. School of Planning and Public Policy. Rutgers—The State University of New Jersey. Report. Available at: http://ceeep.rutgers.edu/wp-content/uploads/2013/11/customerresponse.pdf.

CENELEC. 2016. Smart metering. [www]. Available at: http://www.cencenelec.eu/standards/Sectors/SustainableEnergy/SmartMeters/Pages/default.aspx.

CENELEC. 2012. Framework for Smart Grid Standardization. CEN-CENELEC-ETSI Smart Grid Coordination Group. Report. Available at: ftp://ftp.cen.eu/EN/EuropeanStandardization/HotTopics/SmartGrids/Framework%20Document.pdf.

Chen, P. 2014. The use of big data for outage management in distribution system. International conference on electricity distribution. Report. Available at: http://smartgridcenter.tamu.edu/resume/pdf/cnf/CIRED2014.pdf.

Con Edison. 2016. Con Edison Takes New Approach to Rewarding Customers for Smart Usage. [www]. Available at: http://www.coned.com/newsroom/news/pr20160805.asp.

Energy Authority. 2016a. Key figures for distribution companies. Sähköverkkotoiminnan tekniset tunnusluvut, (In Finnish). Available at: https://www.energiavirasto.fi/web/guest/tunnusluvut2014.

Energy Authority. 2016b. Regulation model 2016 – 2023. Valvontamenetelmät 2016 – 2023, (In Finnish). Available at: https://www.energiavirasto.fi/en/valvontamenetelmat-2016-20231.

Energy Authority. 2013. Electricity market act (2013)'s effect on distribution companies Sähkömarkkinalainsäädännön uudistamisen vaikutuksia sähköverkkotoimintaan. Report. (In Finnish). Available at: https://www.energiavirasto.fi/documents/10179/0/Simo+Nurmi.pdf/ad9cda69-6353-406d-a36e-5d77de59bad2.

Energy Authority. 2007. Determining CIC values. Keskeytystunnuslukujen referenssiarvojen määrittäminen. Report. (In Finnish). Available at: https://www.energiavirasto.fi/33-keskeytystunnuslukujen-referenssiarvojen-maarittaminen.

Enoro Oy. 2016. Meter Data Management. [www]. (In Finnish). Available at: http://www.enoro.com/#!meter-data-management/cgy3. (Accessed July 14, 2016).

ENTSO-E 2013. Supporting Document for the Network Code on Load-Frequency Control and Reserves. Report. Available at: https://www.entsoe.eu/major-projects/network-code-development/load-frequency-control-reserves/Pages/default.aspx.

ENTSO-E & EDSO. 2010. European Electricity Grid Initiative Roadmap and Implementation plan. Report. Available at: http://www.smartgrids.eu/documents/EEGI/EEGI_Implementation_plan_May%202010.pdf.

ESMIG. 2009. We make metering smart. The European Smart Metering Industry Group (ESMIG). Report. Available at: http://esmig.eu/publications.

EURELECTRIC. 2011. 10 Steps to smart grids. EURELECTRIC DSOs' ten-year roadmap for smarter grid deployment in the EU. Report. Available at: http://www.eurelectric.org/media/26140/broch.10steps_lr-2011-030-0304-01-e.pdf.

European Commission. 2011. Standardization Mandate to European Standardization Organizations (ESOs) to support European Smart Grid deployment. Report. Available at: https://ec.europa.eu/energy/sites/ener/files/documents/2011_03_01_mandate_m490_en.pdf

European Parliament. 2009. Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC. Available at: http://www.nezeh.eu/assets/media/fckuploads/file/Legislation/RED_23April2009.pdf

Farhangi, H. 2010. The path of the smart grid. IEEE power and energy magazine. Vol 8 (2010) 18-28. DOI: 10.1109/MPE.2009.934876.

Fingrid. 2016. Power System in Finland. [www]. Available at: http://www.fingrid.fi/en/powersystem/general%20description/Power%20System%20in%20Finland/Pages/default.aspx (Accessed July 28, 2016).

Fingrid. 2016b. Demand Side Management [www]. Available at: http://www.fingrid.fi/en/electricity-market/Demand-Side_Management/Pages/default.aspx.

Fortum Oyj. 2016. Virtual Power Plant. [www]. Available at: http://www.fortum.com/en/corporation/research-and-development/virtual%20power%20plant/pages/default.aspx. (Accessed August 8, 2016).

Gaia Consulting Oy. 2014. Distributed generation's competitiveness and analysis on its overall benefits. Sähkön pientuotannon kilpailukyvyn ja kokonaistaloudellisten hyötyjen analyysi. Report. (In Finnish). Available at: http://docplayer.fi/671154-Sahkon-pientuotannon-kilpailukyvyn-ja-kokonaistaloudellisten-hyotyjen-analyysi.html.

Gauci, A. 2013. Benefits of Feeder Automation Solutions to Improve Quality of Supply and Reduce Operations and Maintenance Costs. Schneider electric. Whitepaper. Available at: http://static.schneider-electric.us/docs/Automation%20Products/0110DB1202.pdf.

GRID+. 2016. European Electricity Grid Initiative (EEGI). [www]. Available at: http://www.gridplus.eu/eegi. (Accessed August 5, 2016).

Gulich, O. 2010. Technological and Business Challenges of Smart Grids, Aggregator's Role in Current Electricity Market. Master of Science Thesis. Lappeenranta. Lappeenranta University of Technology. Available at: http://www.doria.fi/bitstream/handle/10024/62885/nbnfi-fe201003041461.pdf?sequence=3.

Harjula, M. 2008. Proposal for Standardizing and Encoding of Measurement Streams in the New Energy Market. Mittausvirtoihin liityvä standardisointi- ja kooditusehdotus uusilla energiamarkkinoilla. Master of Science Thesis. Lappeenranta. Lappeenranta University of Technology. (In Finnish). Available at: http://www.doria.fi/handle/10024/42808.

Hashmi M. 2011. Survey of smart grids concepts worldwide. VTT. Report. Available at: http://www.vtt.fi/publications/index.jsp.

Heikkilä, T. 2013. Development of regulation methods for security of supply in power distribution grid
. Sähköverkon toimitusvarmuuteen liittyvien valvontamenetelmien kehittäminen. Master of Science Thesis. Tampere. Tampere University of Technology. (In Finnish) Available at: https://www.energiavirasto.fi/documents/10179/0/Diplomity%C3%B6%20Tuukka+Heikkil%C3%A4%20Energiavirasto+FINAL.pdf/5f3b5842-ae34-4aff-af94-9ccd51401598.

Helen Oy. 2016. Sävel Plus. [www]. Available at: https://www.helen.fi/en/electricity/homes/customer-benefits/savel-plus/. (Accessed August 8, 2016).

Hälvä, V. 2013. Development of process data utilization in proactive network management. Master of Science Thesis. Tampere. Tampere University of Technology. Available at: http://dspace.cc.tut.fi/dpub/bitstream/handle/123456789/21391/halva.pdf?sequence=1.

IEA. 2015. Smart Grids in Distribution Networks, Roadmap Development and Implementation. International Energy Agency. International low-carbon energy technology platform. Report. Available at: https://www.iea.org/publications/freepublications/publication/TechnologyRoadmapHow2GuideforSmartGridsinDistributionNetworks.pdf.

IEA. 2011. Technology Roadmap – Smart grids. Energy Agency's Energy Technology Policy Division. Report. Available at: https://www.iea.org/publications/freepublications/publication/smartgrids_roadmap.pdf.

IEEE 2002. P1366 Major Event Day Language Draft. IEEE Standard 1366-1998. Report. Available at: http://grouper.ieee.org/groups/td/dist/sd/doc/2002-08-P1366MajorEventDayLanguageDraft4.pdf.

Jokiniemi, J. 2014. Possibilities of demand response in Finnish industry. Master of Science Thesis. Espoo. Aalto University, School of Engineering. Available at: https://aaltodoc.aalto.fi/handle/123456789/14087.

Kauppi M. (2014). Secondary substation automation utilization potential in Elenia Distribution Network. Muuntamoautomaation hyödyntämismahdollisuudet Elenian jakeluverkossa. Master of Science Thesis. Tampere. Tampere University of Technology. (In Finnish) Available at: http://dspace.cc.tut.fi/dpub/handle/123456789/22211.

Koozehkanani, S., Salemi, S., Sadr, S. 2015. Optimal implementation of feeder automation in medium voltage distribution networks. Electrical Power Distribution Networks Conference (EPDC), 2015 20th Conference on IEEE. Study report. Available at: http://ieeexplore.ieee.org/abstract/document/7330466/.

Lakervi, E., Partanen J. 2009. Power distirubtion technology. Sähkönjakelutekniikka. Helsinki. Gaudeamus Helsinki University Press. ISBN 978-951-672-359-7.

Lappeenrannan Energia Oy. 2014. Lappeenrannan Energia Oy Vuosikertomus. (In Finnish). Available at: http://docplayer.fi/483989-Lappeenrannan-energia-oy-vuosikertomus-2013-3.html.

Larsen, P., LaCommare, K., Eto, J., Sweeney, J. 2015. Assessing Changes in the Reliability of the US Electric Power System. U.S. Department of Energy. Report. Available at: https://emp.lbl.gov/sites/all/files/lbnl-188741_0.pdf.

Lehtonen, M., Kupari, S. 1995. A method for cost benefit analysis of distribution automation. Energy Management and Power Delivery, 1995. Proceedings of EMPD '95., 1995 International Conference on, IEEE. Available at: http://ieeexplore.ieee.org/xpl/mostRecentIssue.jsp?punumber=3588.

Millar J. 2016. ELEC-E8406 - Electricity Distribution and Markets. Department of Electrical Energy Engineering, Aalto University School of Electrical Engineering. Study materials. (In Finnish). Available at: https://mycourses.aalto.fi/course/view.php?id=5249&section=1.

Sadeh, J., Bakhshizadeh, E., Kazemzadeh, R. 2013. A new fault location algorithm for radial distribution systems using modal analysis. International Journal of Electrical Power & Energy Systems. Vol 45 (2013) 271-278. Available at: http://www.sciencedirect.com/science/article/pii/S0142061512005030.

Sarvaranta, A. 2010. A study on smart grids and its deploypment in the EU and Finland. Selvitys älykkäistä sähköveroista ja niiden kehityksestää Euroopan unionissa ja Suomessa. Helsinki. Energiateollisuus ry. Report. (in Finnish). Avilable at: http://energia.fi/sites/default/files/alykkaat_sahkoverkot_2010_diplomityo_anni_sarvaranta.pdf.

Schneider Electric. 2015. Powering an always ON world. Schneider Electric e-book. Available at: http://www.schneider-electric.com/b2b/en/products/product-launch/smart-utility-ebook/.

Siemens. 2016. Intelligent Transformer Substations for Future-Proof Power Distribution. Report. Available at: http://spectrum.ieee.org/webinar/intelligent-transformer-subst-for-futureproof-power-distribution.

Siirto, O. 2011. Customer Damage Evaluation and Network Automation Strategies for Different Urban Zones. 21st International Conference on Electricity Distribution. Report. Available at: https://portal.cleen.fi/_layouts/IWXmlPublications.aspx?Source=SGEM&FileId=757.

Silvast, A., Heine, P., Lehtonen, M., Kivikko, K., Mäkinen, A., Järventausta, P. 2005. The negative impacts of outages. Sähkönjakelun keskeytyksestä aiheutuva haitta. Tampereen teknillinen yliopisto. Report. (In Finnish). Available at: http://ktm.elinar.fi/ktm_jur/ktmjur.nsf/all/6AFAFB826AEF5800C22570E600371215/$file/74642004.pdf.

SM-CG. 2011. Functional reference architecture for communications in smart metering systems. Smart Meters Coordination Group. Report. Available at: ftp://ftp.cencenelec.eu/EN/EuropeanStandardization/HotTopics/SmartMeters/CEN-CLC-ETSI-TR50572%7B2011%7De.pdf.

Soudi, F., and K. Tomsovic. 1998. Optimized distribution protection using binary programming. IEEE Transactions on Power Delivery. Vol 13 (1998) 218-224. DOI: 10.1109/61.660881.

Säntti, J. 2015. Regulatory Requirements for Implementing Demand Response in the Nordic Electricity Markets. Master of Science Thesis. Espoo. Aalto University, School of Engineering. Available at: https://aaltodoc.aalto.fi/bitstream/handle/123456789/19206/master_S%C3%A4ntti_Jori_2015.pdf?sequence=1&isAllowed=y.

Taloussanomat. 2014. Online article. (In Finnish). Available at: http://www.taloussanomat.fi/asuminen/2014/10/31/joka-kotiin-saatiin-juuri-alysahkomittari-kohta-ne-uusitaan-taas/201415194/310.

Tekes. 2013. Groove / solar energy catalogue. Available at: http://www.tekes.fi/Global/Nyt/Uutiset/solar_catalogue_groove_190413.pdf.

TEM. 2008. Promotion of demand response in Finland. Sähkön kysyntäjouston edistäminen. Sähkön kysyntäjouston roolia ja tavoitteita sähkömarkkinoilla selvittäneen työryhmän mietintö. Työ- ja elinkeinoministeriö. Report. (In Finnish). Available at: http://docplayer.fi/2761093-Sahkon-kysyntajouston-edistaminen-sahkon-kysyntajouston-roolia-ja-tavoitteita-sahkomarkkinoilla-selvittaneen-tyoryhman-mietinto.html.

U.S. Department of energy. 2012. Application of automated controls for voltage and reactive power management initial results - Initial Results. Smart Grid Investment Grant Program, U.s Department of energy. Available at: https://www.smartgrid.gov/files/VVO_Report_-_Final.pdf.

Venkatesh, B., Rakesh Ranjan, H. B. Gooi. 2004. Optimal reconfiguration of radial distribution systems to maximize loadability. IEEE Transactions on power systems. Vol 19 (2004) 260-266. DOI: 10.1109/TPWRS.2003.818739.

Verho, P., Sarsama, J., Strandén, J., Krohns-Välimäki, H., Hälvä, V., Hagqvist, O. 2011. Improvement of risk analysis and fault management in large scale outages. Suurhuollon suurhäiriöiden riskianalyysi- ja hallintamenetelmien kehittäminen – Projektin loppuraportti. VTT & Tampere University of Technology. Report. (In Finnish). Available at: http://www.tut.fi/cs/groups/public/@l102/@web/@p/documents/liit/mdbw/mdiz/~edisp/p023819.pdf.

Vihanninjoki V. 2015. Distributed generation in Finland, current status, future, and effect on air quality. Hajautettu energiantuotanto Suomessa, Nykytila ja tulevaisuus sekä vaikutukset ilmanlaatuun. Suomen ympäristökeskus SYKE. (in Finnish). Available at: http://www.syke.fi/download/noname/%7BDD119785-B537-45DE-AEF0-8360DCAB1BDF%7D/111845.

Yle. 2016. Online article. (In Finnish). Available at: http://yle.fi/uutiset/sahko-markkinat_muuttumassa_euroopassa__suomea_uhkaa_jopa_250_miljoonan_lasku/8911059.

Appendix: Interviews

Helen Sähkverkko Oy:
Interviewee: Osmo Siirto (Director, Distribution Network)
Time: 16.9.2016
Location: Osmontie 38, Helsinki, Finland

Technical questions: Helen Sähköverkko Oy	
Number of HV/MV Substations?	22
HV/MV substation Automation level (%)	100
Number of Pole Transformers?	
Number of new Pole Transformers per year?	
Number of Kiosk Transformer?	1800+700
Number of new Kiosk Transformer per year?	
Number of MW pole switches?	
Number of new MW pole switches per year?	
Transformer station (kiosks) automation level (%)	20
How many new kiosks to remote control next year?	50 out of 75

General quations: Helen Sähköverkko Oy	
What legislations / regulations should be renewed in order effectively support the implementation of smart grid technologies?	It should be possible to add components to regulation model's component value list. If a component is not on the list, there are no investments in that particular component.
What challenges do you expect smart grid solutions to solve in the near future for distribution companies (5 to 10 years)?	Tackle problems caused by DG. Ami measurements to 15 minute intervals. To manage consumption decrease in rural areas and increase in urban areas.

Views on the effects of the increasing solar power production?	Need for power and voltage control increases

Turku Energia Sähköverkko Oy
Interviewees: Antti Nieminen (SCADA manager) and Janne Strandén (Network Planner)
Time: 23.9.2016
Location: Linnankatu 65, Turku, Finland

Technical questions: Turku Energia Sähköverkko Oy	
Number of HV/MV Substations?	17
HV/MV substation Automation level (%)	100
Number of Pole Transformers?	314
Number of new Pole Transformers per year?	-
Number of Kiosk Transformer?	974
Number of new Kiosk Transformer per year?	25
Number of MW pole switches?	200
Number of new MW pole switches per year?	-
Transformer station (kiosks) automation level (%)	4,620 %
How many new kiosks to remote control next year?	50 %

General quations: Turku Energia Sähköverkko Oy	
What legislations / regulations should be renewed in order effectively support the implementation of smart grid technologies?	No direct incentive for new technologies. In direct incentives sometimes difficult to interpret
What challenges do you expect smart grid solutions to solve in the near future for distribution companies (5 to 10 years)?	Detecting power quality issues. Managing new consumption patterns due to heat pumps. Better earth fault detection. Managing possible increase in DG.
Views on the effects of the increasing solar power production?	Safety concerns on LV side. New price model needed, more emphasis on capacity?

Elenia Oy
Interviewees: Heikki Paananen (Manager of Operational Planning)
Time: 29.9.2016
Location: Patamäenkatu 7, Tampere, Finland

Technical questions: Elenia Oy	
Number of HV/MV Substations?	135
HV/MV substation Automation level (%)	100
Number of Pole Transformers?	16 400

Number of new Pole Transformers per year?	-
Number of Kiosk Transformer?	6 900
Number of new Kiosk Transformer per year?	1 000
Number of MW pole switches?	1 600
Number of new MW pole switches per year?	Before 2018 300, after this 0
Transformer station (kiosks) automation level (%)	20 %
How many new kiosks to remote control next year?	Fault indication to kiosk stations boost, 20% of kiosks to remote control

General quations: Elenia Oy	
What legislations / regulations should be renewed in order effectively support the implementation of smart grid technologies?	Possibility to add components to 'component value list' in mass installations. Incentives for large volumes. Innovation incentive work well in smaller pilot projects.
What challenges do you expect smart grid solutions to solve in the near future for distribution companies (5 to 10 years)?	Faster FLIR. EV charging infrastructure. Self-monitoring grid. 'Kiosks' without the need to go inside. More support to fault management from big data analytics. Remote controlled substations as a requirement.
Views on the effects of the increasing solar power production?	Need for LV automation increases. More accurate AMI needed. Detecting new consumption patterns.

Järvi-Suomen Energia Oy
Interviewees: Mika Huttunen (Head of operation, distribution) and Tuomo Härkönen (Operation technician)
Time:30.9.2016
Location: Johtokatu 1, Mikkeli, Finland

Technical questions: Järvi-Suomen Energia Oy	
Number of HV/MV Substations?	47
HV/MV substation Automation level (%)	100
Number of Pole Transformers?	6800
Number of new Pole Transformers per year?	50
Number of Kiosk Transformer?	1400
Number of new Kiosk Transformer per year?	200
Number of MW pole switches?	3000
Number of new MW pole switches per year?	100
Transformer station (kiosks) automation level (%)	20 %
How many new kiosks to remote control next year?	40 out of 200

General questions: Järvi-Suomen Energia Oy	
What legislations / regulations should be renewed in order effectively support the implementation of smart grid technologies?	Continues power supply requirements for phone operators' base stations. Network value model does not encourage reuse of components.
What challenges do you expect smart grid solutions to solve in the near future for distribution companies (5 to 10 years)?	Capture directional earth fault and residual current
Views on the effects of the increasing solar power production?	Under investigation

Caruna Oy and Caruna Espoo Oy (combined):
Interviewees: Jörgen Dahlqvist (Head of Network Operation) and Kimmo Vainiola (Head of control center)
Time: 5.10.2016
Location: Upseerinkatu 2, Espoo, Finland

Technical questions: Caruna Oy	
Number of HV/MV Substations?	153
HV/MV substation Automation level (%)	100
Number of Pole Transformers?	
Number of new Pole Transformers per year?	
Number of Kiosk Transformer?	
Number of new Kiosk Transformer per year?	
Number of MW pole switches?	
Number of new MW pole switches per year?	
Transformer station automation (kiosks) level (%)	
How many new kiosks to remote control next year?	

General questions: Caruna Oy	
What legislations / regulations should be renewed in order effectively support the implementation of smart grid technologies?	In general, the Finnish regulation framework does not interfere with smart grid development and implementation. Only energy storages are a bit restrictive on DSO side. 1. 1. Energy Authority “*Erittämisasetus*” Chapter 2.3. states that DSO may not own energy storage which is connected to medium voltage grid -> Removal of the ownership restriction. 2. 2. Regulation methods should add energy storage to unit price list.
What challenges do you expect smart grid solutions to solve in the near future for distribution companies (5 to 10 years)?	Demand side management is in the key role in cost-efficient solution for power balance issues. DSOs must have active role to support the TSO as almost all new DSM-resources are in DSO grid.

Views on the effects of the increasing solar power production?	Within 5-10 years there should not be a problem as Finnish grid dimensions are quite generous due to electrical heating and cold winters. During summer, there is plenty of free capacity and during winter added PV-production might ease out peak load situations. On Tso level there might be scarcity on inertia and balancing power resources as conventional power plants are phased out.

Tampereen Sähköverkko Oy
Interviewee: Hannu Hoivassilta (Project Manager)
Time: 5.10.2016
Location: via e-mail

Technical questions: Tampereen Sähköverkko Oy	
Number of HV/MV Substations?	18
HV/MV substation Automation level (%)	100 %
Number of Pole Transformers?	400
Number of new Pole Transformers per year?	4
Number of Kiosk Transformer?	600
Number of new Kiosk Transformer per year?	40
Number of MW pole switches?	5
Number of new MW pole switches per year?	1
Transformer station automation (kiosks) level (%)	13 %
How many new kiosks to remote control next year?	5 out of 40

General quations: Tampereen Sähköverkko Oy	
What legislations / regulations should be renewed in order effectively support the implementation of smart grid technologies?	It should be possible to add all network investment into network value
What challenges do you expect smart grid solutions to solve in the near future for distribution companies (5 to 10 years)?	Grid stability, safety, protection, tariffs and contracts bring challenges that should be tackled
Views on the effects of the increasing solar power production?	No big problems in Finland